MASTERS ENERGY INC.

EXPERIENCE. FOCUS. BALANCE.

2005 ANNUAL REPORT

MASTERS ENERGY INC. IS AN ALBERTA-BASED CORPORATION ENGAGED IN THE ACQUISITION, EXPLORATION AND DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESERVES IN WESTERN CANADA. MASTERS' COMMON SHARES ARE LISTED ON THE TORONTO STOCK EXCHANGE UNDER THE TRADING SYMBOL "MSY".

ABBREVIATIONS

Oil and natural gas liquids

bbl	barrel
mbbls	thousand barrels
mmbbls	million barrels
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
mboe	thousand barrels of oil equivalent
NGL	natural gas liquids

Natural gas

mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
GJ	gigajoule

Other

AECO	EnCana Corporation natural gas storage facility located at Suffield, Alberta
°API	Specific gravity of crude oil measured on the American Petroleum Institute gravity scale (28° API or higher is generally referred to as light crude oil)
ARTC	Alberta Royalty Tax Credit
boe	Barrel of oil equivalent of crude oil and natural gas on the basis of 1 bbl equals 6 mcf of natural gas
US	United States
WTI	West Texas Intermediate, the reference price paid in US dollars at Cushing, Oklahoma for crude oil of 40°API

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HIGHLIGHTS

Years ended December 31	2005	2004
Financial *($ thousands, except per share amounts)*		
Gross revenue	**22,929**	11,978
Funds generated by operations	**12,159**	5,634
Per share - basic	**0.84**	0.42
- diluted	**0.81**	0.41
Net earnings	**3,611**	428
Per share - basic	**0.25**	0.03
- diluted	**0.24**	0.03
Capital expenditures	**27,533**	10,920
Working capital deficit	**5,013**	4,116
Long-term debt	**14,093**	-
Operations		
Production		
Crude oil *(bbls/d)*	**697**	558
NGL *(bbls/d)*	**11**	7
Natural gas *(mcf/d)*	**3,276**	1,706
Total production *(boe/d, 6:1)*	**1,254**	849
Average sales price		
Crude oil *($/bbl)*	**44.82**	36.51
NGL *($/bbl)*	**55.19**	44.25
Natural gas *($/mcf)*	**8.87**	6.59

ADVISORIES

The calculations of barrels of oil equivalent ("boe") are based on a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil. A boe unit may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf=1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Certain information regarding the Company, including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of commodity prices, currency fluctuations, uncertainties of reserves estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated. Masters assumes no obligation to update the forward-looking statements contained herein or to update the reasons why actual results could differ from those contemplated by the forward-looking statements, unless so required by applicable securities law.

PRESIDENT'S MESSAGE TO SHAREHOLDERS

At Masters Energy, during 2005, we made significant progress toward our long term goals by performing well in a number of aspects of our business. We forged ahead with a very high level of activity in 2005 and we expect that will continue in 2006. Specifically, we drilled 22 wells, acquired in excess of 15,000 net acres of undeveloped land and purchased an asset which has evolved into a core area for Masters. Through investments in undeveloped land and seismic in 2004 and 2005, Masters has expanded the inventory of exploration and development opportunities which we expect will provide economic growth in 2006.

During 2005, Masters' strategy was to:

- *exploit our large undeveloped land base;*
- *add value to our core area at Little Bow through infill drilling and waterflood optimization;*
- *maintain a strong balance sheet and utilize our debt capacity for strategic acquisition opportunities;*
- *grow our asset base through efficient use of capital; and*
- *enhance shareholder value.*

Masters is pleased to report to our shareholders that we made considerable progress on these objectives.

- *We exploited our undeveloped land base by drilling 22 wells with a 73 percent success rate.*
- *We significantly increased the value of our Little Bow property by drilling six infill oil wells, one water injection well and two natural gas wells. In 2005, the present value of this property increased by 83 percent to $33.3 million (proved plus probable reserves at present value - 10 percent pre-tax).*
- *We maintained a strong balance sheet which allowed us to use Masters' debt capacity to acquire a new core area in the North Peace River Arch area of Alberta.*
- *Masters asset base grew as we:*
    - *increased annual production by 48 percent to 1,254 boe per day from 849 boe per day;*
    - *replaced 307 percent of annual production (based on proved plus probable reserves additions and revisions);*
    - *added 1.6 million boe of proved plus probable reserves; and*
    - *utilized capital efficiently and achieved a recycle ratio of 1.9 times.*
- *We enhanced shareholder value by:*
    - *increasing funds generated by operating activities to $0.84 per share, an increase of 100 percent;*
    - *increasing the market value of Masters' shares which rose to $6.47 per share, a 149 percent increase from the December 31, 2004 closing price; and*
    - *increasing the value of Masters' reserves by 107 percent (103 percent per share) during 2005.*

Although Masters performed well in 2005, we were disappointed with production volumes in the fourth quarter. Daily production briefly increased to 1,600 boe/d near the end of the year before a natural gas well at Hector became uneconomic, was shut-in and reduced our average daily production rate. Masters intended to drill 13 wells in the fourth quarter but lack of rig availability restricted our drilling to 10 wells. As well, lack of equipment, services or surface access issues delayed several projects we had scheduled for start-up production during the last quarter of 2005. These issues delayed certain production additions until 2006. We expect the production volumes anticipated during the fourth quarter of 2005 will be realized before spring break-up in 2006.

Revised guidance

In November 2005, Masters issued guidance that quantified our production rate expectations for 2006 in the range of 2,100 - 2,200 boe/d of production and $25 million of exploration and development capital expenditures. Our guidance at that time assumed US$60.00 per WTI barrel for crude oil price and Cdn$10.00 per thousand cubic feet for natural gas price. In light of the deferral of some of our production additions and expectations for lower natural gas prices in 2006, we believe it is prudent to revise our expectations for the coming year. As a result, we have revised 2006 guidance for our production rate to a range of 1,800 - 2,000 boe/d and capital expenditures, excluding acquisitions, to $21 million.

Outlook

Masters' strategy for 2006 is to continue to exploit our large undeveloped land base, build value within our core producing areas, continue to expand our prospects inventory and pursue several high impact exploration plays in areas outside our core areas. We expect the recent strong demand for acquisitions will continue with that element of our business being competitive throughout 2006. Masters will maintain a strategy of pursuing acquisitions that fit strategically and have the potential to add shareholder value.

The current business environment for the oil and natural gas sector remains attractive. Although we expect natural gas prices will soften in the short term, we expect longer term commodity prices will be strong. Relatively low interest rates, high demand for energy and reasonable access to capital markets sustain the current strong business environment in the oil and natural gas sector. Robust levels of activity also create challenges with respect to cost pressures. We expect that high demand for oilfield services and supplies and delays with respect to implementing field work will continue. We recognize that we may need to adjust Masters' timing expectations accordingly.

Masters is fortunate to employ a team of experienced, knowledgeable and talented people. The combination of our excellent team, significant investment opportunities, our solid foundation of properties and attractive business fundamentals in the oil and natural gas sector underpins our strong sense of optimism for the future.

In summary, Masters has achieved significant accomplishments since becoming public in March 2004. Our successful growth has only been possible with the effort and support from all of Masters' stakeholders. On behalf of our Board of Directors, I sincerely thank each stakeholder and invite you to join me in looking forward to what Masters can accomplish in 2006.

Geoffrey C. Merritt
President and Chief Executive Officer

March 20, 2006

ADVISORIES

Management's discussion and analysis ("MD&A") of Masters Energy Inc. ("Masters", the "company", "we" or "our"), provided as of March 20, 2006, should be read in conjunction with the audited financial statements presented within this annual report.

Basis of Presentation - The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP measurements

The MD&A contains the term 'funds generated by operations' and 'funds generated by operations per share', which should not be considered an alternative to, or more meaningful than, net earnings or cash flow from operating activities as determined in accordance with GAAP as an indicator of the company's performance. Masters' determination of funds generated by operations or funds generated by operations per share may not be comparable to that reported by other companies. Management uses funds generated by operations to analyze operating performance and leverage and considers funds generated by operations to be a key measure as it demonstrates the company's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between net earnings and funds generated by operations can be found in the statements of cash flows in the audited financial statements. The company presents funds generated by operations per share, which is prohibited under GAAP. Per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Presentation of boe

Masters bases calculations of barrels of oil equivalent ("boe") on a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil. The boe unit may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf equals 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Forward-looking information

This MD&A contains forward-looking or outlook information with regard to Masters within the meaning of applicable securities laws. Forward-looking statements may include estimates, plans, expectation, forecasts, guidance or other statements that are not statements of fact. Masters believes the expectations reflected in such forward-looking statements are reasonable. However, no assurance can be given that such expectations will prove to be correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward looking statements. These risks include but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, Masters' ability to replace and expand oil and natural gas reserves, the sources and adequacy of funding for capital investments, the company's future growth prospects and current and expected financial requirements, the cost of future reclamation and site restoration, Masters' ability to enter into or renew leases and to secure adequate product transportation, changes in environmental and other regulations and general economic conditions. These statements speak only as of the date of this MD&A and Masters does not undertake an obligation to update our forward-looking statements except as required by law.

Disclosure controls and procedures

Chief executive officer, Geoffrey C. Merritt, and chief financial officer, Randall P. Boyd, evaluated the effectiveness of Masters' disclosure controls and procedures as of December 31, 2005 and concluded that Masters' disclosure controls and procedures were effective to ensure that information the company is required to disclose in its annual and interim filings or other reports filed or submitted by it under provincial legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by Masters is accumulated and communicated to company management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

The evaluation took into consideration Masters' Disclosure Policy and the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered the company's processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information. All controls and procedures, no matter how well designed, have inherent limitations. These controls and procedures provide reasonable, but not absolute, assurance that financial information is accurate and complete.

CORPORATE OVERVIEW

Masters Energy Inc. was incorporated under the Alberta Business Corporations Act on August 28, 2003. During the fall of 2003 Masters completed a private placement of 17,752,000 special warrants for gross proceeds of $17.8 million. On December 22, 2003 Masters closed the acquisition of producing oil and gas properties in the Little Bow area of southern Alberta. At the time of acquiring the property, daily production was approximately 450 boe/d with a composition of 90 percent oil and 10 percent gas.

On February 26, 2004, Masters and Terraquest, a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco common share for every 12 common shares of Terraquest and Masters shareholders received one Amalco common share for every two common shares of Masters. After giving effect to the transaction, Amalco had approximately 14.4 million common shares outstanding.

During 2005, Masters acquired oil and natural gas producing properties in the North Peace River Arch area for $7.2 million. At the time of the acquisitions the properties produced approximately 160 boe/d and provided ownership in one natural gas processing plant, five compressor stations and associated infrastructure.

In 2005, Masters drilled 22 exploration and development wells, resulting in six oil and 10 natural gas wells for an overall success rate of 73 percent. In addition, we drilled a water injection well at Little Bow to enhance oil recovery from the existing pool. During 2005, we spent $20.3 million on our exploration and development program.

Results of operations for the years ended December 31, 2005 and 2004

PRODUCTION

	2005	2004
Annual production		
Crude oil *(bbls)*	**254,450**	204,049
Natural gas liquids ("NGL") *(bbls)*	**3,838**	2,550
Natural gas *(mcf)*	**1,195,641**	624,536
Total *(boe)*	**457,562**	310,688
Daily production		
Crude oil *(bbls/d)*	**697**	558
NGL *(bbls/d)*	**11**	7
Natural gas *(mcf/d)*	**3,276**	1,706
Total *(boe/d)*	**1,254**	849

For the year ended December 31, 2005 total production increased 48 percent and averaged 1,254 boe/d (2004 - 849 boe/d) with oil production including NGL comprising 56 percent (2004 - 66 percent) and natural gas, 44 percent (2004 - 34 percent). Production increased during 2005 as a result of drilling and tying in successful wells and the acquisition of producing properties in the North Peace River Arch area.

Based on drilling activity budgeted for 2006 and production expected from existing producing properties, Masters forecasts a total production rate of 1,800 - 2,000 boe/d comprised of 40 percent oil including NGL and 60 percent natural gas.

PRICES

	2005	2004
Crude oil - before hedging *($/bbl)*	**44.82**	37.66
Hedging settlement *($/bbl)*	**-**	(1.15)
Crude oil - after hedging *($/bbl)*	**44.82**	36.51
NGL *($/bbl)*	**55.19**	44.25
Natural gas *($/mcf)*	**8.87**	6.59

West Texas Intermediate ("WTI") is the benchmark for North American oil prices and is the crude oil type against which NYMEX futures contracts are priced. Canadian crude oil prices are based on refiners' postings at hubs such as Edmonton and Hardisty, Alberta. The basis for Canadian postings is the WTI price at Cushing, Oklahoma minus a transportation differential, adjusted for the US/Canadian currency exchange rate and for relative quality and regional market conditions.

During 2005, North America experienced historically high price levels for WTI crude oil due to concerns regarding supply. As a result, the average price for a barrel of WTI crude during 2005 increased more than US$15.00 to US$56.59. During 2005, the Canadian dollar strengthened relative to the US dollar with the average currency exchange rate for $1.00 Canadian increasing to US$0.83 (2004 - US$0.77). The higher exchange rate reduced the price received for delivery of crude within Canadian markets. Quality price differential postings on medium types of crude oil also experienced a negative effect during 2005. The average differential between Edmonton light sweet crude postings and Hardisty Bow River medium crude increased to approximately $25.00 per bbl (2004 - $15.00 per bbl).

In 2005, Masters' average field price for crude oil was $44.82 per bbl versus $69.18 per bbl for light sweet crude oil postings at Edmonton, Alberta. All crude revenues during 2005 were from sales to spot markets. Masters did not hedge any production during 2005. Overall, Masters' 2005 crude oil production was 84 percent medium and 16 percent lighter gravity crude.

The 2004 average crude price recorded in the above table is net of hedging settlements of $0.2 million. The acquisition of Terraquest Energy Corporation included a hedging contract. The loss in 2004 amounted to the balance in excess of the fair value of the hedging contract liability recorded at the time of the acquisition.

The typical reference for US natural gas prices is NYMEX at Henry Hub, Louisiana while the reference for Canadian prices is at Nova Inventory Transfer ("NIT") or the AECO Hub. Masters sold all natural gas produced during 2005 and 2004 to the spot market according to the AECO reference price. Masters did not enter into any fixed or hedged type natural gas sales contracts during 2005 and 2004.

Masters' average natural gas price in 2005 was $8.87 per mcf versus $8.69 per mcf for spot postings of the AECO reference price.

Masters' management complies with a Risk Management Policy approved by the company's board of directors. The objective of Masters' risk management activities is to reduce exposure to decreases in commodity prices that would materially impact the funds generated by operating activities which fund capital spending and, ultimately, affect Masters' growth. Any transactions entered would be with credit worthy purchasers and would be for less than one year. To ensure Masters has sufficient physical volumes available to meet the obligations of these transactions, Masters limits the volumes contracted to no more than 50 percent of forecasted production.

The forecasted average wellhead prices used for Masters' 2006 budget were $45.00 (US$60.00 WTI) per bbl of crude oil and Cdn$8.00 per mcf of natural gas. The 2006 forecasted foreign currency exchange rate is estimated to average US$0.85 per Cdn$1.00.

REVENUES

($ thousands, except as indicated)	*2005*	*2004*
Crude oil revenue	**11,405**	7,685
Hedging charge	**-**	(234)
Crude oil revenue, after hedging charge	**11,405**	7,451
NGL revenue	**211**	113
Natural gas revenue	**10,600**	4,116
Total petroleum and natural gas revenue	**22,216**	11,680
Royalty and other revenue	**713**	298
Total revenue	**22,929**	11,978
Total petroleum and natural gas revenue per boe *($)*	**48.55**	37.59
Total revenue per boe *($)*	**50.11**	38.55

Petroleum and natural gas revenue for the 2005 year increased 90 percent to $22.2 million due to a 47 percent increase in production as well as a 29 percent increase in realized commodity prices. A $0.2 million loss recorded for the balance remaining on the hedge contract assumed through the acquisition of Terraquest partially offset crude oil revenues for 2004. That hedging contract expired on December 31, 2004.

Royalty and other revenue increased by 139 percent to $0.7 million as a result of royalty interests acquired with the North Peace River Arch acquisition as well as higher commodity prices throughout 2005.

Based on forecasted production volumes and commodity prices, Masters forecasts an increase in oil and natural gas revenues of approximately 35 - 45 percent during 2006.

ROYALTIES

($ thousands, except as indicated)	*2005*	*2004*
Crown	**4,382**	2,122
Alberta Royalty Tax Credit ("ARTC")	**(500)**	(184)
Crown, net of ARTC	**3,882**	1,938
Freehold and gross overriding	**813**	441
Total royalties	**4,695**	2,379
Per boe *($)*	**10.26**	7.66
Average royalty rate, before hedge charge *(%)* (1)	**21.1**	20.0
Average royalty rate, after hedge charge *(%)* (1)	**21.1**	20.4

(1) A percentage of total petroleum and natural gas revenue

Royalties paid for the year ended December 31, 2005 increased 97 percent. Masters' average royalty rate, before recording the effects of hedging charges, increased to 21.1 percent during 2005 (2004 - 20.0 percent). The average royalty rate, after recording the effects of hedging charges, increased to 21.1 percent (2004 - 20.4 percent). The 2005 royalty expense is comprised of 83 percent (2004 - 81 percent) paid to the crown with the remainder paid to freehold and gross overriding royalty owners. In 2005, Masters paid royalties amounting to $10.26 per boe (2004 - $7.66 per boe).

Masters anticipates forecasted royalty rates for 2006 will be consistent with historical rates.

OPERATING EXPENSES

($ thousands, except as indicated)	2005	2004
Production expenses	4,168	2,816
Transportation costs	-	37
Total operating expenses	4,168	2,853
Per boe ($)	9.11	9.18

In 2005, operating expenses per boe decreased one percent to $9.11 per boe. Operating expenses were higher than anticipated due to third party processing fees associated with prior years' production and a one time increase in electrical power rates at our Little Bow facilities during the fourth quarter of 2005. In 2004, operating expenses included transportation costs incurred on contracted natural gas deliveries.

Masters expects 2006 operating expenses per boe to decrease as production volumes increase and fixed costs are spread over a larger production base from our core areas. However, we anticipate that increased industry activity may result in variable costs, such as utility and service fees, partially offsetting the decrease in fixed operating expenses per boe.

Netback analysis

($ per boe)	2005	2004
Oil and natural gas revenues, before hedge charge	48.55	38.35
Hedge charge	-	(0.75)
Oil and natural gas revenues, after hedge charge	48.55	37.60
Royalty and other revenue	1.56	0.96
	50.11	38.56
Royalty expense, net of ARTC	(10.26)	(7.66)
Operating expenses	(9.11)	(9.18)
Operating netback	30.74	21.72

GENERAL AND ADMINISTRATIVE

($ thousands, except as indicated)	2005	2004
Gross general and administrative	1,904	1,529
Operating recoveries	(78)	(121)
Capitalized expenses	(617)	(504)
General and administrative, before stock-based compensation	1,209	904
Future stock-based compensation expense	227	173
Total general and administrative expense	1,436	1,077
General and administrative expense, before stock-based compensation, per boe ($)	2.64	2.91
Total general and administrative expense per boe ($)	3.14	3.47

On a per boe basis, total general and administrative expense in 2005 decreased 10 percent to $3.14 per boe (2004 - $3.47 per boe). The 25 percent increase in gross general and administrative expenses in 2005 to $1.9 million (2004 - $1.5 million), resulted mainly from expenses for initial annual reporting and regulatory filing, as well as implementation of results-based compensation. During 2005, Masters capitalized approximately one-third of general and administrative costs associated with exploration and development activities. Masters capitalizes general and administrative expense directly related to exploration and development activities as these costs are associated with adding reserves. General and administrative expenses for 2005 and 2004 include a non-cash provision of $0.2 million for future stock-based compensation.

We anticipate that total general and administrative expenses for 2006 will be similar to 2005. Based on forecasted production and capital spending, we estimate 2006 staff levels will be similar to 2005. As we bring new production on stream, we anticipate a reduction in general and administrative costs per boe.

INTEREST EXPENSE

($ thousands, except as indicated)	*2005*	*2004*
Total interest expense	**414**	112
Per boe *($)*	**0.91**	0.36

Interest expense increased 270 percent to $0.4 million in 2005 (2004 - $0.1 million). This reflects an increase in average debt levels during the year as interest rates remained relatively stable. At year-end 2005, Masters had bank debt of $14.1 million (2004 - $3.4 million). Average debt outstanding during the year was approximately $9.5 million. Increased exploration and development activities during the latter half of 2005 led to a change in the year-end balance from the average annual borrowing level. Our average interest rate to borrow during the year was 4.36 percent.

Masters forecasts average bank debt and interest rates for 2006 will moderately increase from 2005. For 2006, we anticipate that Masters' ratio of debt to funds generated by operations will be approximately one to one.

DEPLETION, DEPRECIATION AND ACCRETION

($ thousands, except as indicated)	*2005*	*2004*
Depletion	**6,502**	4,283
Depreciation	**11**	13
Accretion on asset retirement obligations	**114**	171
Total depletion, depreciation and accretion expense	**6,627**	4,467
Depletion, depreciation and accretion expense per boe *($)*	**14.48**	14.38

During 2005, depletion, depreciation and accretion expense increased 48 percent to $6.6 million (2004 - $4.5 million). This increase is primarily the result of Masters' increase in production. Depletion, depreciation and accretion marginally increased to $14.48 per boe during 2005 (2004 - $14.38 per boe) as a result of 2005 finding and development costs attributed to reserves additions being comparable to the historical carrying values of assets eligible for depletion.

Masters performs an annual ceiling test in accordance with the Canadian Institute Chartered Accountants' full cost accounting guidelines, using forecasted prices determined by the independent qualified reserves evaluation firm that evaluates Masters' reserves. As well, Masters performs a quarterly ceiling test using adjusted prices received at period end. At December 31, 2005, the impairment recognition portion of the ceiling test indicated the estimated undiscounted future cash flows from proven reserves exceeded the carrying values of producing petroleum and natural gas properties and, therefore, a ceiling test adjustment was not required.

INCOME TAXES

($ thousands, except as indicated)	*2005*	*2004*
Future	**1,975**	662
Capital	**3**	-
Total income taxes	**1,978**	662
Effective tax rate *(%)*	**35.4**	60.7

Income taxes, future and capital increased 199 percent in 2005 to $2.0 million (2004 - $0.7 million). Increased earnings before taxes, as a result of higher commodity prices and increased production volumes, were the main reason for the increase in total income taxes. Based on available tax pools, forecasted capital spending levels and commodity prices, Masters does not expect to be currently taxable for 2006.

Masters has approximately $46.6 million in tax pools to shelter taxable income in the future years. The table below shows estimated 2005 tax pools.

($ thousands)	*2005*
Canadian Exploration Expense	8,988
Canadian Development Expense	6,773
Canadian Oil and Gas Property Expense	20,596
Undepreciated Capital Cost	9,371
Other	824
Total	46,552

NET EARNINGS

In 2005, net earnings increased 654 percent to $3.6 million (2004 - $0.4 million), primarily from increased revenues driven by higher commodity prices and larger production volumes. Net earnings increased in 2005 to $7.89 per boe (2004 - $1.38 per boe) while funds generated by operating activities increased in 2005 to $27.19 per boe (2004 - $18.45 per boe).

Earnings ratios

($ thousands, except as indicated)	*2005*	*2004*
Net earnings	**3,611**	428
Earnings ratios *(%)*		
Return on capital (1)	**10.1**	2.3
Return on investment (2)	**9.5**	2.0
Return on shareholder equity (3)	**12.2**	1.9

(1) Net earnings plus after-tax financing charges on debt divided by average of opening and closing capital employed. Capital employed is a total of equity and bank debt.
(2) Net earnings plus after-tax financing charges on debt divided by average net investment. Net investment is total assets less current liabilities. Return on investment is calculated using the average opening and closing net investment.
(3) Net earnings are divided by average of opening and closing shareholders' equity.

Net earnings per boe

($/boe)	*2005*	*2004*
Total revenues (after hedge charges)	**50.11**	38.55
Royalties	**(10.26)**	(7.65)
Operating expenses	**(9.11)**	(9.18)
Net operating income	**30.74**	21.72
General and administrative (excluding stock-based compensation expense)	**(2.64)**	(2.91)
Interest expense	**(0.91)**	(0.36)
Funds generated by operating activities	**27.19**	18.45
Depletion, depreciation and accretion	**(14.48)**	(14.38)
Stock-based compensation	**(0.50)**	(0.56)
Taxes	**(4.32)**	(2.13)
Net earnings	**7.89**	1.38

SHARE CAPITAL

During 2005, Masters issued 159,666 common shares (2004-nil) on the exercise of stock options and performance warrants by employees. Stock options granted to employees during the year amounted to 50,000 common shares (2004 - 670,000 common shares).

The weighted average common shares outstanding, for the three month period ended December 31, 2005 was 14,490,650 basic (15,481,767 diluted). For the year ended December 31, 2005 the basic weighted average shares outstanding was 14,420,197 (2004 - 13,521,707) and the diluted average shares outstanding was 15,090,130 (2004 - 13,716,226). Shares issued and outstanding, as at December 31, 2005, were 14,523,313 (2004 - 14,363,647). As of the date of the MD&A, the number of shares issued and outstanding had not changed from 2005 year-end.

	2005	2004
Outstanding common shares *(thousands)*		
Weighted average outstanding common shares		
Basic	**14,420**	13,522
Diluted	**15,090**	13,716
Outstanding common shares at December 31		
Common shares (basic)	**14,523**	14,364
Common share options	**1,127**	1,255
Common share warrants	**870**	1,000
Common shares outstanding (diluted)	**16,520**	16,619
Per share information *($ thousands except as indicated)*		
Net earnings	**3,611**	428
Net earnings per share *($)*		
Basic	**0.25**	0.03
Diluted	**0.24**	0.03
Funds from operating activities	**12,159**	5,634
Funds from operating activities per share *($)*		
Basic	**0.84**	0.42
Diluted	**0.81**	0.41
Total asset book value	**60,016**	37,291
Total asset book value per share *($)* (1)		
Basic	**4.13**	2.60
Diluted	**3.63**	2.24
Book value (shareholders' equity) (1)	**31,791**	27,570
Book value per share *($)*		
Basic	**2.19**	1.92
Diluted	**1.92**	1.66
Proved plus probable reserves *(mboe)*	**3,986**	2,834
Reserves per 100 shares *(boe)* (1)		
Basic	**27.4**	19.7
Diluted	**24.1**	17.1
Annual production *(mboe)*	**458**	311
Production per 100 shares *(boe)* (1)		
Basic	**3.2**	2.2
Diluted	**2.8**	1.9

(1) Calculated using outstanding common shares, options and warrants at year-end.

Net asset value

Masters' net asset value per share at December 31, 2005 increased by 74 percent to $4.86 per basic share (2004 - $2.80 per share) and by 65 percent to $4.63 per diluted share (2004 - $2.80 per share).

(thousands of dollars, except as indicated)	**2005 Constant price**	**2005 Forecast price (1)**	**2004 Forecast price (1)**
Proved plus probable reserves value (10% discount before tax)	**78,173**	**74,761**	36,127
Undeveloped acreage (2)	**14,965**	**14,965**	8,245
Net debt	**(19,106)**	**(19,106)**	(4,116)
Basic net asset value	**74,032**	**70,620**	40,256
Projected proceeds on exercise of options and warrants	**5,847**	**5,847**	6,309
Diluted net asset value	**79,879**	**76,467**	46,565
Common shares outstanding *(thousands)*			
Basic	**14,523**	**14,523**	14,364
Diluted	**16,520**	**16,520**	16,619
Net asset value per common share *($)*			
Basic (3)	**5.10**	**4.86**	2.80
Diluted (3)	**4.84**	**4.63**	2.80

(1) The reserves values are based on before tax future cash flows as evaluated by the Company's independent qualified reserves evaluators, McDaniel & Associates Consultants Ltd. using their future commodity price forecast.
(2) The land values are determined using an estimated value in 2005 of $150 (2004 - $100) per undeveloped acre.
(3) Calculated using outstanding common shares, options and warrants at year-end.

Share trading activity

Masters common shares are listed and posted for trading on the TSX and trade under the symbol MSY. The following table summarizes monthly trading activity of Masters common shares for the year-ended December 31, 2005.

Month	*Volume*	*High*	*Low*	*Close*
January	315,300	2.68	2.31	2.60
February	2,384,000	3.85	2.60	3.70
March	1,449,500	4.20	3.10	3.40
April	639,000	3.65	3.05	3.41
May	471,700	3.49	3.06	3.40
June	1,985,400	3.80	3.35	3.64
July	826,200	4.09	3.62	3.96
August	1,017,200	4.49	3.83	4.41
September	520,400	4.70	4.31	4.55
October	1,048,400	5.45	4.60	5.15
November	648,100	6.05	5.00	5.60
December	654,800	6.95	5.68	6.47

Year ended December 31, 2004

Month	Volume	High	Low	Close
January	-	-	-	-
February[1]	-	-	-	-
March	219,800	3.25	2.45	2.55
April	299,200	2.69	2.20	2.50
May	319,100	2.48	2.20	2.30
June	250,100	2.45	2.00	2.40
July	306,300	2.49	2.25	2.45
August	165,700	2.65	2.40	2.54
September	437,600	2.77	2.46	2.70
October	1,472,100	2.80	2.56	2.65
November	1,003,600	2.85	2.58	2.65
December	382,500	2.69	2.30	2.60

(1) Masters common shares commenced trading on the TSX as of March 5, 2004.

CAPITAL EXPENDITURES

Total capital expenditures during 2005 were $27.5 million which included $20.3 million for exploration and development expenditures and $7.2 million for the acquisition of producing oil and natural gas properties in the North Peace River Arch area.

Our 2005 exploration and development activity resulted in 22 (gross) exploration and development wells drilled, acquisition of 15,648 net acres of undeveloped crown land and completion of several 3D seismic programs to acquire 70 square miles of data. In 2005, Masters' exploration and development capital allocation was approximately $12.8 million in southern Alberta and $7.5 million in northern and central Alberta.

($ thousands)	*2005*	*2004*
Land	**2,401**	889
Geological and geophysical	**3,037**	620
Drilling and completions	**10,430**	6,652
Equipping and facilities	**4,390**	2,757
Other	**31**	2
Total exploration and development capital	**20,289**	10,920
Producing property acquisitions	**7,244**	-
Terraquest Energy Corporation	**-**	19,584
Total capital expenditures	**27,533**	30,504

Undeveloped land holdings

Masters' undeveloped land increased by 20 percent to 99,766 net acres and we have access to approximately 19,200 acres of option lands or control of approximately 119,000 total acres. In 2005, Masters acquired 15,648 net acres through crown land sales and approximately 10,600 net undeveloped acres through the North Peace River Arch acquisitions. At December 31, 2005, in the North Peace River Arch core area, Masters had 19,200 gross acres with an option to earn an interest. Masters will earn an interest in these option lands upon performing certain activities. The term on these lands extends through to the end of December 31, 2006. The average working interest of the undeveloped lands Masters owned at December 31, 2005 was 45 percent.

	2005		2004	
Alberta *(acres)*	**Gross**	**Net**	**Gross**	**Net**
Southern	**32,367**	**24,298**	28,813	20,432
Northern and central	**190,411**	**75,468**	129,043	62,994
Total owned undeveloped land	**222,778**	**99,766**	157,856	83,426
Total controlled option land	**19,200**		-	

Finding and development costs

During 2005, our exploration and development program resulted in total proved reserves additions, after prior year revisions, of 860,000 boe, or 1,110,000 boe on a proved plus probable basis. Masters' total finding and development costs were $23.59 per proved boe and $18.28 per proved plus probable boe. After adding in the change in future development capital, finding and development costs were $24.54 per proved boe and $19.05 per proved plus probable boe. Total finding and development and net acquisition costs were $21.44 per proved boe and $15.80 per proved plus probable boe.

The combined 2003 to 2005 capital programs including the acquisitions of Little Bow, Terraquest and North Peace River Arch resulted in finding and development costs of $17.14 per proved boe and $13.39 per proved plus probable boe. After adding in the change to estimated future development capital, finding and development costs were $17.40 per proved boe and $13.61 per proved plus probable boe. The reserves disclosed for 2005 and 2004 conform with the requirements of National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities.

2005 Finding and development (F&D) and net acquisition (FD&A) costs

	Capital expenditures *($ thousands)*	**Proved reserves additions** *(mboe)*	**Proved costs** *($/boe)*	**Proved plus probable reserves additions** *(mboe)*	**Proved plus probable costs** *($/boe)*
F&D exploration and development programs before revisions	20,289	702	28.90	942	21.54
F&D exploration and development program after revisions (a)	20,289	860	23.59	1,110	18.28
Change in proved future development capital (b)	819	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	853	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	21,108	860	24.54	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	21,142	n/a	n/a	1,110	19.05
Net acquisition activity, working interest reserves	5,244	309	16.97	500	10.49
Net acquisition activity, royalty interest reserves	2,000	115	17.39	133	15.04
Total net acquisition activity, company interest reserves (f)	7,244	424	17.08	633	11.44
Total 2005 FD&A costs before future development costs (a+f)	27,533	1,284	21.44	1,743	15.80
Total 2005 proved FD&A costs including future development costs (d+f)	28,352	1,284	22.08	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development costs (e+f)	28,386	n/a	n/a	1,743	16.29

2004 Finding and development (F&D) and net acquisition (FD&A) costs

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development programs before revisions	10,920	343	31.84	420	26.00
F&D exploration and development program after revisions (a)	10,920	572	19.09	588	18.57
Change in proved future development capital (b)	178	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	288	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	11,098	572	19.40	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	11,208	n/a	n/a	588	19.06
Net acquisition activity, working interest reserves	19,584	840	23.31	1,149	17.04
Net acquisition activity, royalty interest reserves	-	-	-	-	-
Total net acquisition activity, company interest reserves(f)	19,584	840	23.31	1,149	17.04
Total 2004 FD&A costs before future development costs (a+f)	30,504	1,412	21.60	1,737	17.56
Total 2004 proved FD&A costs including future development costs (d+f)	30,682	1,412	21.73	n/a	n/a
Total 2004 proved plus probable FD&A costs including future development costs (e+f)	30,792	n/a	n/a	1,737	17.73

Combined 2003 to 2005 finding and development (F&D) and net acquisition (FD&A) costs

Masters Energy Inc. commenced operations December 22, 2003 with the acquisition of the Little Bow property in southern Alberta. The combined 2003 to 2005 results are more representative of management's efforts as presented in the table below.

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development programs before revisions	31,592	1,045	30.23	1,362	26.91
F&D exploration and development program after revisions (a)	31,592	1,432	22.06	1,698	19.22
Change in proved future development capital (b)	997	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	1,141	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	32,589	1,432	22.76	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	32,733	n/a	n/a	1,698	19.28
Net acquisition activity, working interest reserves	31,838	2,270	14.03	3,057	10.41
Net acquisition activity, royalty interest reserves	2,000	115	17.39	133	15.04
Total net acquisition activity, company interest reserves(f)	33,838	2,385	14.19	3,190	10.61
Total 2003 to 2005 FD&A costs before future development costs (a+f)	65,430	3,817	17.14	4,888	13.39
Total 2003 to 2005 proved FD&A costs including future development costs (d+f)	66,427	3,817	17.40	n/a	n/a
Total 2003 to 2005 proved plus probable FD&A costs including future development costs (e+f)	66,571	n/a	n/a	4,888	13.61

Reserves replacement

Masters 2005 capital expenditure program replaced production by a factor of 2.6 times on a proved basis and 3.5 times on a proved plus probable basis.

	2005	2004
Production *(mboe)*	**458**	311
Proved reserves additions after revisions *(mboe)*	**1,169**	572
Proved replacement ratio	**2.55**	1.84
Proved plus probable reserves additions after revisions *(mboe)*	**1,610**	588
Proved plus probable replacement ratio	**3.52**	1.89

Recycle ratio

Recycle ratio is a measure for evaluating the effectiveness of a company's re-investment in its exploration and development program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per barrel of oil equivalent to that year's finding and development costs per boe.

	2005
Operating netbacks *($/boe)*	30.74
Proved FD&A costs after revisions and including the change in future development cost *($/boe)*	22.08
Proved reinvestment efficiency ratio	1.4
Proved plus probable FD&A costs after revisions and including the change in future development cost *($/boe)*	16.29
Proved plus probable reinvestment efficiency ratio	1.9

Drilling results

During 2005, Masters drilled 22 exploration and development wells resulting in six oil wells and 10 natural gas wells for an overall success rate of 73 percent. Of the total wells drilled, 16 were in southern Alberta and the remaining six were in northern and central Alberta.

	2005		2004	
(wells)	Gross	Net	Gross	Net
Oil	6	6.0	-	-
Natural gas	10	7.2	6	3.5
Dry and abandoned	6	4.4	8	5.7
Total	22	17.6	14	9.2
Success rate *(%)*	73	75	43	38

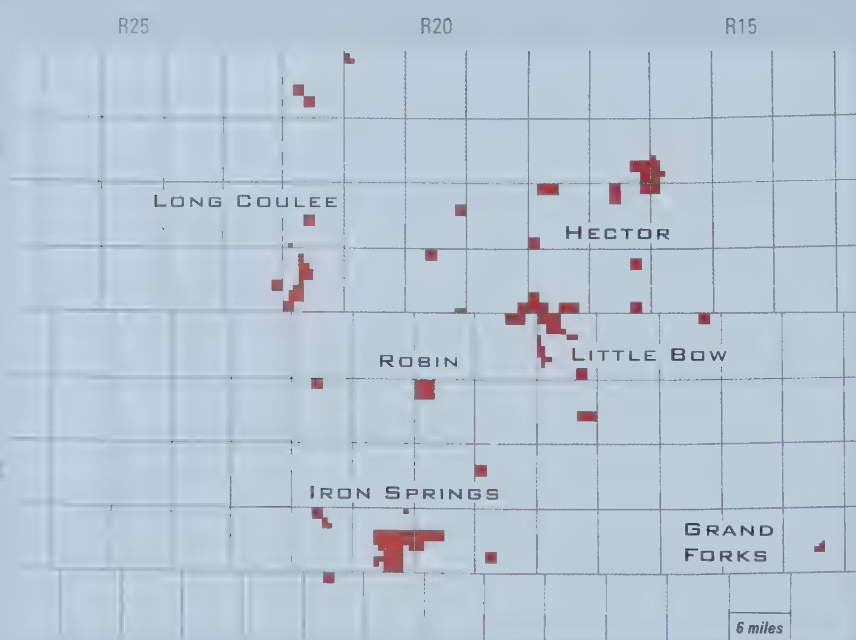
CORE AREA ACTIVITY

In 2006, we will continue to focus on exploiting opportunities within our core producing areas at Little Bow and the North Peace River Arch region as well as concentrating on Masters' large undeveloped land base (approximately 100,000 net acres) in Alberta. We anticipate spending $21 million on exploration and development activities. Masters anticipates allocating approximately 60 percent of capital spending to opportunities in the North Peace River Arch area. Masters also expects to develop numerous new prospects in addition to those currently identified.

Southern Alberta

The 2003 acquisition of Little Bow provided Masters with an entry into southern Alberta. At the time of the acquisition the Little Bow property was producing approximately 450 boe/d. The Terraquest acquisition in February 2004 strategically enhanced Masters' operations in southern Alberta with interests in producing properties at Little Bow, Long Coulee, Grand Forks, Hector and Badger. The Terraquest acquisition also provided 22,000 net acres of undeveloped lands for future drilling.

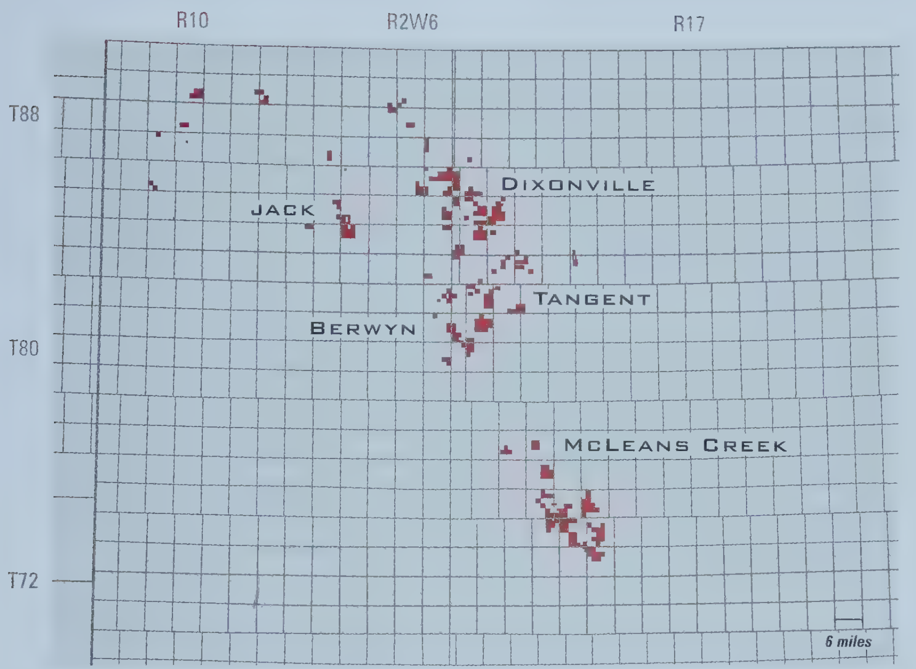
During 2005, Masters drilled 16 exploration and development wells resulting in six oil wells and six natural gas wells for an overall success rate of 75 percent. At Little Bow, we drilled a total of 10 wells including six infill wells in the main producing pool. We expanded the battery and water handling facility during 2005 and drilled a water injection well into the existing pool.



In 2005 and early 2006, Masters completed several 3D seismic surveys on exploratory lands which has resulted in several future drilling locations. We will pursue additional exploration concepts on, or in reasonable proximity to, existing Masters' lands.

For 2006, we expect to allocate approximately one-third of capital spending to southern Alberta which includes drilling 7-10 medium depth wells. Masters' southern area provided approximately 80 percent of 2005 total production.

Northern and Central Alberta



In 2005, Masters spent $7.2 million for acquisitions of North Peace River Arch properties which created a second core producing area for Masters. These acquisitions provided 160 boe/d of production, 10,600 net undeveloped acres, ownership in several strategic field facilities and a large seismic data base associated with the properties.

In addition to the initial acquisitions Masters spent $7.5 million to drill six wells (four were natural gas wells), acquire more than 10,000 net undeveloped acres, expand existing production facilities and complete several large 3D seismic programs.

In addition to the acquired undeveloped acreage, we control option lands of 19,200 acres as a result of three transactions negotiated during the latter half of 2005. On a section-equivalent basis, the option lands represent 30 sections.

At the end of 2005 and in early 2006, Masters shot approximately 94 square miles of 3D seismic. This will provide the basis for an active drilling program in 2006. Generally, our drilling prospects are multi-zone to depths of 1,300 meters, targeting the Montney, Gething, Cadotte, Cadomin, Charlie Lake, Bluesky, Dunvegan, Paddy and Spirit River.

For 2006, approximately two-thirds of Masters capital spending is anticipated to be in the northern and central areas of Alberta, drilling approximately 25 to 30 wells.

CONTRACTUAL OBLIGATIONS

As part of our land acquisition strategy in our core areas, Masters will commit to industry partners to drill wells, shoot seismic programs or tie-in previously drilled wells to earn interests in undeveloped land. Masters has committed to drill four wells and tie-in a suspended oil and natural gas well to earn lands. Masters estimates these work commitments amount to approximately $1.5 million. These commitments are scheduled in Masters' 2006 capital expenditures program currently approved by the board of directors at $21 million. Masters has contractual obligations on operating leases for field equipment. The operating leases are considered short term and due within one year, if demanded. The table below shows payments due within the periods indicated.

($ thousands)	*Total*	*Less than 1 year*	*1 - 3 years*	*4 - 5 years*	*After 5 years*
Bank debt	14,093	-	14,093	-	-
Farm-in commitments	1,500	1,500	-	-	-
Operating leases	114	114	-	-	-
Office lease	418	87	269	62	-
Total contractual obligations	16,125	1,701	14,362	62	-

LIQUIDITY AND CAPITAL RESOURCES

Total capitalization at December 31, 2005 was $118.9 million (2004 - $44.5 million) with the market value of common shares representing 79 percent of total capitalization. Net debt represented 16 percent and asset retirement obligations plus future income taxes accounted for five percent.

Total market capitalization

($ thousands, except as indicated)	*2005*	*%*	*2004*	*%*
Common shares outstanding *(thousands)*	**14,523**		14,364	
Closing share price at December 31 *($)*	**6.47**		2.60	
Total market capitalization	**93,966**	**79**	37,346	84
Working capital deficiency, excluding bank debt	**5,013**		692	
Bank debt	**14,093**		3,424	
Net debt	**19,106**	**16**	4,116	9
Asset retirement obligations	**3,316**	**3**	3,044	7
Future income taxes	**2,005**	**2**	30	-
Total capitalization	**118,393**	**100**	44,536	100
Net debt to total capitalization	**16%**		9%	

At December 31, 2005 Masters had borrowed approximately $14.1 million (2004 - $3.4 million) and had a working capital deficit of $5.0 million (2004 - $0.7 million) amounting to total net debt of $19.1 million (2004 - $4.1 million). Net debt for 2005 represents approximately 1.6 times (2004 - 0.7 times) funds generated by operating activities of $12.2 million (2004 - $5.6 million) and approximately 1.1 to 1.3 times budgeted 2006 funds generated by operating activities.

The company has a bank revolving term facility of $18 million to fund future activities. The facility is a borrowing base facility determined by Masters' latest reserves assessment, results of operations, current and forecasted commodity prices and the prevailing economic market. The facility is reviewed annually in April. As at December 31, 2005, Masters had drawn $14.1 million of the revolving term facility.

The capital intensive nature of our activities can create a negative working capital position in quarters with high levels of exploration and development capital spending.

The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude and natural gas. This occurs on the 25th day following the month in which the production is sold. As a result Masters' sales revenues are collected in an organized manner. The company monitors purchaser credit positions to mitigate any potential credit losses. To the extent Masters has joint interest activities with industry partners we must collect, on a monthly basis, partners' share of capital and operating expenses. These collections are subject to normal industry risk. Masters collects in advance for significant amounts related to partners' share of capital expenditures in accordance with the industry operating procedures. At December 31, 2005 Masters had no material accounts receivable deemed uncollectible.

Accounts payable consists of invoices payable to trade suppliers relating to office and field operating activities and our capital spending program. Invoices are processed within Masters' normal payment period.

We continually manage Masters' capital spending program by monitoring forecasted production, commodity prices and anticipated cash flow. Should circumstances arise that negatively affect cash flow, Masters is capable of reducing the level of future capital spending.

We will fund our future investing activities, which consist primarily of capital expenditures on oil and natural gas activities, with working capital, cash flow from operations, a limited amount of bank debt, and, possibly, from the issuance of new equity.

Debt ratios

($ thousands, except as indicated)	***2005***	***2004***
Working capital deficiency, excluding bank debt	**5,013**	692
Bank debt	**14,093**	3,424
Net debt	**19,106**	4,116
Debt to funds generated by operating activities ratio		
Funds generated by operating activities	**12,159**	5,634
Trailing net debt	**19,106**	4,116
Years of funds flow from operating activities to repay trailing net debt		
Current year funds generated by operating activities	**1.6**	0.7
Estimated forward funds generated by operating activities	**1.2**	0.4
Asset coverage ratio		
Total assets	**60,016**	37,291
Net debt	**19,106**	4,116
Asset coverage	**3.14**	9.06
Debt/equity ratio		
Net debt	**19,106**	4,116
Shareholders' equity	**31,791**	27,570
Debt/equity	**0.60**	0.15

OUTLOOK

The acquisitions of the North Peace River Arch and Little Bow properties established a strong production base from which Masters can grow. With an experienced technical team, a large undeveloped land base (100,000 net acres) and a number of internally-generated prospects, we are well positioned for growth. We believe Masters can deliver production averaging 1,800 - 2,000 boe/d in 2006 from internally-generated exploration and development. The board of directors has approved a $21 million capital program which focuses on exploiting existing internal opportunities and on continuing to build an inventory of exploration and development opportunities expected to provide growth through 2007 and beyond.

In addition to our ongoing exploration and development program, Masters will seek growth through acquisitions that are strategic and have the potential to add future value.

2006 Capital budget

Masters' 2005 capital program expanded our core areas in southern and northern Alberta by adding prospective lands and a large seismic data base. Through the efforts of this program, we established a large inventory of future drilling opportunities. In 2006 we expect to drill approximately 38 - 45 wells in our current areas of focus.

Masters anticipates 2006 funds generated by operating activities will reach approximately $17-$19 million. This is based on forecasted 2006 average production of 1,800 - 2,000 boe/d, average commodity prices at the wellhead of $45.00 per bbl for crude oil (US$60.00 per barrel WTI) and $8.00 per mcf for natural gas, foreign exchange of US$0.85 and costs remaining at historical levels.

We are forecasting our 2006 capital program at $21 million with an approximate allocation of $5 million for land and seismic, $11 million for drilling and completions, and $5 million for equipment and facilities. We forecast that net debt of $19.1 million, at December 31, 2005, will increase modestly to approximately $21 - 23 million at 2006 year-end.

2006 Sensitivities

Based on forecast assumptions, Masters provides the following sensitivities to indicate the potential impact on funds from operating activities in the event of changes in commodity prices and/or the foreign currency exchange rate.

($ thousands, except as indicated)	***Funds generated by operating activities***	***Per share - basic** ($)*
Impact on 2006:		
Change in WTI oil price of US$5.00 per bbl	1,400	0.10
Change in natural gas price of Cdn$1.00 per mcf	1,800	0.12
Change in US dollar to Cdn dollar of US$0.01	200	0.02

SELECTED QUARTERLY INFORMATION

This financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and measurement currency is the Canadian dollar.

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operations								
Production								
Oil *(bbls/d)*	707	688	715	678	588	597	556	488
NGL *(bbls/d)*	10	15	11	6	13	5	9	2
Natural gas *(mcf/d)*	3,619	3,872	3,055	2,538	2,406	1,980	1,653	800
Total *(boe/d)*	1,320	1,349	1,236	1,107	1,002	932	841	619
Pricing								
Oil, before hedging *($/bbl)*	42.50	56.92	41.64	38.14	36.91	42.40	37.10	33.60
Hedging costs	-	-	-	-	(0.01)	(4.25)	-	-
Oil, after hedging *($/bbl)*	42.50	56.92	41.64	38.14	36.90	38.15	37.10	33.60
NGL *($/bbl)*	60.85	59.56	49.56	46.12	50.72	40.20	36.86	45.11
Natural gas *($/mcf)*	11.29	9.09	7.34	6.83	6.62	6.24	6.51	7.35
Total *($/boe)*	54.18	55.84	42.71	39.28	38.09	37.90	37.95	35.82
Financial *($ thousands, except as indicated)*								
Total revenue	6,908	7,175	4,836	4,010	3,679	3,319	2,952	2,028
Funds from operating activities	2,915	4,476	2,699	2,069	1,676	1,513	1,391	1,055
Net earnings (loss)	630	1,781	643	557	(124)	79	(49)	521
Per share - basic	0.04	0.12	0.04	0.04	(0.01)	0.01	-	0.05
Per share - diluted	0.04	0.12	0.04	0.04	(0.01)	0.01	-	0.05
Capital spending								
Exploration and development	11,570	2,805	2,806	3,108	3,240	2,531	2,761	2,388
Acquisitions/(dispositions)	31	(339)	7,552	-	-	-	-	20,174
Total assets	60,016	51,142	48,130	38,830	37,291	35,518	34,833	34,271
Working capital (deficiency)	(5,013)	1,381	323	(5,155)	(4,116)	(2,551)	(1,533)	(163)
Long-term debt	14,093	11,911	13,137	-	-	-	-	-
Shareholders' equity	31,791	31,033	28,884	28,184	27,570	27,639	27,504	27,508
Common shares								
Weighted average common shares outstanding *(thousands)*								
Basic	14,491	14,462	14,364	14,364	14,364	14,364	14,364	10,987
Diluted	15,482	15,146	14,931	14,801	14,614	14,553	14,505	11,184
Trading activity								
Volume *(thousands)*								
Total	2,351	2,467	3,096	4,149	2,858	910	868	220
Daily	38	39	48	67	45	14	14	12
Price *($ per share)*								
High	6.95	4.70	3.80	4.20	2.85	2.77	2.69	3.25
Low	4.60	3.62	3.05	2.31	2.30	2.25	2.00	2.45
Closing	6.47	4.55	3.64	3.40	2.60	2.70	2.40	2.55

Factors that caused variations over the quarters

Masters completed four significant acquisitions since its initial financing in the fourth quarter of 2003 which have impacted production growth:

- *The acquisition of the Little Bow property in southern Alberta on December 22, 2003 added approximately 450 boe/d consisting of approximately 90 percent crude oil production. Proved plus probable reserves acquired were approximately 1.4 million boe with an estimated reserves life index of 8.6 years.*

- *The acquisition of Terraquest Energy Corporation on February 26, 2004 added production of approximately 400 boe/d consisting of approximately 60 percent natural gas. Proved plus probable reserves acquired were approximately 1.1 million boe with an estimated reserves life index of 7.9 years based on production at the time of acquisition.*

- *The two acquisitions of producing properties in the North Peace River Arch area of northwest Alberta on June 3, 2005 and September 12, 2005 added approximately 160 boe per day consisting primarily of natural gas production. Proved plus probable reserves acquired were approximately 0.5 million boe with an estimated reserves life index of 7.0 years.*

Production growth, other than the acquisitions, is a result of Masters' exploration and development activities. Timing of production is subject to timing of drilling and facility construction.

Growth in revenue and cash flow is the combination of increased production and strong commodity prices. Generally, commodity prices were consistently strong throughout 2004 and 2005. Oil prices for medium grade quality crude experienced a large drop in the latter portion of the 2004 fourth quarter due to wider than historical quality differentials. This impacted the prices Masters received during the fourth quarter of 2004 and throughout 2005 as a majority of our crude production is medium quality.

Depletion, depreciation, accretion and future income taxes influence net earnings. Masters estimates reserves internally every quarter based on acquisition and drilling activities. Independent qualified reserves evaluation engineers determine annual reserves, the results of which can affect fourth quarter reserves additions. Enacted changes to federal and provincial income tax rates for the oil and gas industry impact future income taxes.

The development of future drilling prospects and seasonal field conditions influence capital spending. Cash flow and bank debt primarily funded capital spending.

FOURTH QUARTER ANALYSIS

	Q4 2005	Q3 2005	Q4 2004	% Change Q4 2005 vs Q3 2005	% Change Q4 2005 vs Q4 2004
Operations results					
Production					
Crude oil *(bbls/d)*	**707**	**688**	588	3	20
NGL *(bbls/d)*	**10**	**15**	13	(33)	(23)
Natural gas *(mcf/d)*	**3,619**	**3,872**	2,406	(7)	50
Total *(boe/d)*	**1,320**	**1,349**	1,002	(2)	32
Pricing (after hedging)					
Crude oil *($/bbl)*	**42.50**	**56.92**	36.90	(25)	15
NGL *($/bbl)*	**60.85**	**59.56**	50.72	2	20
Natural gas *($/mcf)*	**11.29**	**9.09**	6.62	24	71
Selected financial results *($ thousands, except as indicated)*					
Total revenue	**6,908**	**7,175**	3,679	(4)	88
Royalties	**(1,815)**	**(1,271)**	(824)	43	120
Operating expense	**(1,471)**	**(1,000)**	(809)	47	82
General and administrative	**(398)**	**(312)**	(334)	28	20
Funds generated by operating activities	**2,915**	**4,476**	1,676	(35)	74
Depletion, depreciation and accretion	**2,184**	**1,728**	1,309	26	67
Net earnings (loss)	**630**	**1,781**	(124)	(86)	298
Per share - basic *($)*	**0.04**	**0.12**	(0.01)	(83)	300
Per share - diluted *($)*	**0.04**	**0.12**	(0.01)	(83)	300
Capital spending					
Exploration and development	**11,570**	**2,805**	3,240	313	257
Acquisitions/(dispositions)	**31**	**(339)**	-	109	100
Total capital spending	**11,604**	**2,466**	3,240	371	258
Working capital (deficiency)	**(5,013)**	**1,381**	(4,116)	(463)	22
Long-term debt	**14,093**	**11,911**	-	18	100
Shareholders' equity	**31,791**	**30,996**	27,570	3	15
Weighted average common shares outstanding *(thousands)*					
Basic	**14,491**	**14,462**	14,364	-	1
Diluted	**15,482**	**15,146**	14,614	2	6

PRODUCTION

Production for the fourth quarter 2005 decreased two percent to 1,320 boe/d compared to the third quarter at 1,349 boe/d but increased 32 percent compared to the fourth quarter of 2004. The production decrease in the fourth quarter occurred when final installation of new water handling facilities at Little Bow temporarily suspended production for several days. Also, surface access delays and lack of rig availability delayed new production additions. Production briefly reached 1,600 boe/d during the 2005 fourth quarter. However, a natural gas well at Hector became uneconomic and was shut-in which adversely affected average daily production for that period. Production increases since the 2004 fourth quarter resulted from successful drilling coming on stream and acquisition of producing properties in the North Peace River Arch area during 2005 second and third quarters.

REVENUES

Revenues for the 2005 fourth quarter decreased four percent to $6.9 million compared to $7.2 million in the 2005 third quarter and increased 88 percent from the 2004 fourth quarter. In the quarter ended December 31, 2005, Edmonton Par postings were lower for crude oil as compared to the third quarter. Record widening of the quality differential for medium types of crude oil to a difference of approximately $28.69 per bbl between the Edmonton Par posting for lighter quality crude and Hardisty Bow River medium crude negatively impacted Masters' 2005 fourth quarter revenues. However, revenues for the 2005 fourth quarter increased over the same period in 2004 as a result of both higher total production and stronger commodity prices.

ROYALTIES

Royalties for the 2005 fourth quarter increased 43 percent to $1.8 million compared to $1.3 million in the 2005 third quarter and increased 120 percent from the 2004 fourth quarter. The majority of royalty expense incurred during the quarters was payable to the crown. Masters' November 2005 price received for natural gas was significantly less than the Alberta reference price resulting in higher than normal crown royalties relative to revenue received. In addition, Masters maximized its ARTC claim on eligible crown royalties during the 2005 fourth quarter and, therefore, the amount of royalties paid to the crown increased compared to the 2005 third quarter. Royalties for the period ended December 31, 2005 increased from the same period in 2004 as a result of higher oil and natural gas revenues. We anticipate the future average royalty rate relative to oil and natural gas revenues will be consistent with historical royalty rates.

OPERATING EXPENSES

Operating expenses for the 2005 fourth quarter increased 47 percent to $1.5 million from $1.0 million in the 2005 third quarter. Third party processing charges for production in prior periods and higher than normal electrical power rates at the Little Bow facility pushed operating expenses higher than anticipated in the 2005 fourth quarter. For the three months ended December 31, 2005 operating expenses increased 82 percent from the same period in 2004 as result of the previously noted exceptions and higher production. Masters forecasts operating costs will average approximately $8.50 per boe during 2006.

GENERAL AND ADMINISTRATIVE

The 2005 fourth quarter general and administrative expense increased 28 percent to $0.4 million from the 2005 third quarter and 20 percent from the 2004 fourth quarter. General and administrative expenses averaged $3.28 per boe for the 2005 fourth quarter compared to $2.51 per boe in the 2005 third quarter and $3.62 per boe in the 2004 fourth quarter. The 2005 fourth quarter general and administrative expenses include provisions for the annual audit and reserves reports. Masters forecasts 2006 general and administrative expenses, including a non-cash provision for future stock-based compensation of approximately $0.2 million, at approximately $2.20 per boe.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion expense for the 2005 fourth quarter was $2.2 million compared to $1.7 million for the 2005 third quarter and $1.3 million for the 2004 fourth quarter. Depletion, depreciation and accretion provision for the 2005 fourth quarter was $17.98 per boe compared to $13.93 per boe in the 2005 third quarter and $14.27 per boe for the 2004 fourth quarter. The depletion rate per boe for the 2005 fourth quarter reflected the disproportionate amount of 2005 exploration and development activities that occurred during the fourth quarter. The increase in the depletion rate since the 2004 fourth quarter was due to acquisition of the North River Arch properties and elevated exploration and development activities throughout 2005.

INCOME TAXES

The future income tax provision for the 2005 fourth quarter was $0.3 million compared to $0.9 million for the 2005 third quarter and $0.5 million for the 2004 fourth quarter. This resulted in an effective tax rate of 29 percent for the 2005 fourth quarter compared to 35 percent for the 2005 third quarter. The effective rate for the 2005 fourth quarter decreased due to higher than anticipated provincial credits on crown royalties claimed during the period.

NET EARNINGS

Net earnings for the 2005 fourth quarter were $0.6 million compared to $1.8 million for the 2005 third quarter and a loss of $0.1 million during the 2004 fourth quarter. The decrease in net earnings for 2005 fourth quarter compared to 2005 third quarter is mainly due to higher royalty and operating expenses. For the three months ended December 31, 2005, the increase in net earnings compared to the same period in 2004 is due to higher revenues from increased production and stronger commodity prices.

CAPITAL EXPENDITURES

During the 2005 fourth quarter Masters spent $11.6 million on exploration and development capital including $1.3 million in land, $2.5 million in seismic, $5.3 million in drilling and completions and $2.5 million in facilities. During the quarter ended December 31, 2005, we drilled 10 wells resulting in three oil and two natural gas wells, acquired 5,448 net acres of undeveloped land, completed several 3D seismic programs over exploration acreage in North Peace River Arch and MacGregor and expanded water handling facilities at Little Bow.

Capital spending during the 2005 fourth quarter was $11.6 million compared to $2.8 million in the 2005 third quarter and to $3.2 million in the 2004 fourth quarter.

CRITICAL ACCOUNTING ESTIMATES

1. Depletion and depreciation expense of petroleum and natural gas properties

Masters follows the full cost method of accounting by initially capitalizing all costs related to exploration for, and the development of, petroleum and natural gas reserves. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and lease and well equipment. Costs capitalized are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified reserves evaluation engineers. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The depletion and depreciation base excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

Masters performs a ceiling test, whereby, if the carrying value of the oil and natural gas properties less accumulated depletion and depreciation, related asset retirement obligations and the lesser of cost and fair value of unproven properties exceeds the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at the company's credit-adjusted risk-free rate of interest, using forecast prices and costs. Any impairment recognized is recorded as additional depletion and depreciation expense.

The amounts recorded for depletion and depreciation of oil and natural gas properties, and the ceiling test, are based on estimates. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

2. Asset retirement obligations

Masters recognizes the liability for asset retirement obligations associated with the abandonment of oil and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the company's credit-adjusted risk-free interest rate. The future costs are estimates that are subject to measurement uncertainty and any change would impact the liability.

3. Stock-based compensation

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income effect are based on estimates of the future volatility of Masters' share price, expected lives of the options, expected dividends and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

4. Income taxes

The determination of the company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability and expense may differ from that estimated and recorded.

5. Business combinations

Business combinations are accounted for using the purchase method of accounting. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value involves many assumptions. The valuation of acquired oil and natural gas properties is based on the discounted proved plus probable reserves as determined by an independent qualified reserves evaluator using future commodity prices and costs. Masters internally estimates undeveloped resource property values.

CHANGES IN ACCOUNTING PRINCIPLES

Masters did not adopt any changes in accounting principles in 2005.

RECENT ACCOUNTING PRONOUNCEMENTS

Management is assessing the following new and revised accounting pronouncements that have been issued and are not yet effective.

1. Non-monetary transactions

In the quarter ending March 31, 2006 Masters will adopt CICA handbook Section 3831 "Non-Monetary Transactions". Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair market value measurement. Masters does not expect application of this new standard to have a material impact on its financial statements.

2. International financial reporting standards ("IFRS")

Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada ratified in 2006. As part of that plan, accounting standards in Canada for public companies will converge with IFRS over the next five years. Masters will continue to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

BUSINESS RISKS AND UNCERTAINTIES

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector.

Masters is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Masters' business has inherent risk and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include market fluctuations in commodity prices, interest rates and currency exchange rates. Operational risks include industry competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The exploration for and production of oil and gas requires manpower and capital. Masters employs highly qualified experienced staff who have demonstrated the ability to generate quality drilling prospects utilizing the latest technological tools to increase the probability of success. The probability of drilling a successful well is enhanced when the company explores in core areas that have multi-zone potential, focusing on low to moderate risk prospects with a limited exposure to high-risk, high-reward opportunities. Masters maintains operational control in a majority of its prospects, which enables the company to control the timing, assignment of resources and capital invested in exploration and development opportunities.

A wide number of factors beyond Masters' control influence commodity prices. To manage this risk, we concentrate in regions which permit multiple delivery points to markets and enter into fixed price commodity contracts, on a limited portion of production, within the company's self imposed hedging guideline.

The acquisition of undeveloped mineral leases, supply of services and production equipment at competitive prices is essential to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult and expensive to obtain. Increased prices for supplies and services can inflate costs of operations and potentially erode product netbacks. Masters attempts to mitigate this risk by developing strong long-term relationships with industry participants, suppliers and contractors.

There are potential risks to the environment inherent to Masters' business activities. To mitigate these risks, Masters conducts high standards of operations and follows safety procedures designed to protect and maintain the environment, and public and employee safety, with respect to all corporate operations on behalf of shareholders, staff and stakeholders at large. Masters minimizes environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and carrying adequate insurance coverage.

ADDITIONAL INFORMATION

Additional information about Masters, including our Annual Information Form ("AIF"), is filed and viewable on SEDAR at www.sedar.com. To request a copy of AIF contact Masters Energy Inc. 1150, 736 6th Avenue SW, Calgary, Alberta, Canada T2P 3T7 or e-mail boyd@mastersenergy.com. This information is also accessible on Masters' web site www.mastersenergy.com.

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (NI 51-101 F3)

Management of Masters is responsible for the preparation and disclosure of information with respect to the Corporation's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs;
(ii) the related estimated future net revenue;
(b) (i) proved oil and natural gas reserves estimated as at December 31, 2005 using constant prices and costs; and,
(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of the Corporation has

(c) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
(d) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and,
(e) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas information;
(g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
(h) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Geoffrey C. Merritt
President and Chief Executive Officer

Randall P. Boyd
Chief Financial Officer

Fred C Coles

Fred Coles
Director and Chair of the Reserves Committee
March 20, 2006

Kerry D. Lyons
Director and Member of the Reserves Committee

REPORT OF INDEPENDENT QUALIFIED RESERVES EVALUATORS (NI 51-101 F2)

To the Board of Directors of Masters Energy Inc. (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2005. The reserves data consist of the following:
   - *(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and*
     (ii) the related estimated future net revenue; and
   - *(b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and*
     (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's Board of Directors:

			Net present value of future net revenue (before income taxes, 10% discount rate) ($ thousands)			
Independent qualified reserves evaluator or auditor	***Preparation date of evaluation report***	***Location of reserves (country or foreign geographic area)***	***Audited***	***Evaluated***	***Reviewed***	***Total***
McDaniel & Associates Consultants Ltd.	December 31, 2005	Canada	$nil	$74,761	$nil	$74,761

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Phil Welch

P. A. Welch
McDaniel & Associates Consultants Ltd.
Calgary, Alberta
March 13, 2006

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION (NI 51-101 F1)

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 13, 2006. The effective date of the Statement is December 31, 2005 and the preparation date of the Statement is March 13, 2006.

Background

Masters Energy Inc. ("Masters" or the "Corporation") was incorporated under the Alberta Business Corporations Act on August 28, 2003. During the fall of 2003 Masters completed a private placement of 17,752,000 special warrants for gross proceeds of $17,752,000. On December 22, 2003 Masters acquired producing oil and natural gas properties in the Little Bow area of southern Alberta for $7.0 million.

On February 26, 2004, Masters and Terraquest Energy Corporation ("Terraquest"), a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco common share for every 12 common shares of Terraquest and Masters shareholders receive one Amalco common share for every two common shares of Masters. After giving effect to the transaction, Amalco had approximately 14.36 million common shares outstanding.

The consequence to the reverse take-over and amalgamation of Terraquest on February 26, 2004 was the loss of any relevant comparative analysis for Masters in the 2003 fiscal year.

The Corporation's head and registered office is located at Suite 1150, 736 - 6 Avenue SW, Calgary, Alberta, T2P 3T7.

Unless the context otherwise requires, "Masters" or the "Corporation" means Masters Energy Inc.

Masters common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MSY".

Disclosure of reserves data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by McDaniel with an effective date of December 31, 2005 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the province of Alberta.

Disclosure provided herein in respect of boe units may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf equals 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

RESERVES DATA - CONSTANT PRICES AND COSTS

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2005
Constant prices and costs

Reserves category	Light and medium oil Gross (mbbls)	Light and medium oil Net (mbbls)	Natural gas liquids Gross (mbbls)	Natural gas liquids Net (mbbls)	Natural gas Gross (mmcf)	Natural gas Net (mmcf)	Total Gross (mboe)	Total Net (mboe)
Proved								
Developed producing	1,750	1,625	11	7	4,064	3,155	2,438	2,158
Developed non-producing	51	45	11	7	2,329	1,728	451	340
Undeveloped	36	90	-	-	54	77	45	103
Total proved	1,837	1,760	22	15	6,447	4,960	2,934	2,601
Probable	526	494	9	6	3,111	2,387	1,053	897
Total proved plus probable	2,363	2,253	31	21	9,559	7,347	3,987	3,498

Net present values of future net revenue

Reserves category ($ millions)	Before income taxes discounted at (percent per year) 0	5	10	15	20	After income taxes discounted at (percent per year) 0	5	10	15	20
Proved										
Developed producing	63.5	53.9	47.0	41.9	37.9	56.3	47.8	41.8	37.3	33.9
Developed non-producing	15.6	12.5	10.4	8.9	7.8	10.4	8.2	6.8	5.7	5.0
Undeveloped	4.0	3.2	2.7	2.3	2.0	2.7	2.1	1.8	1.5	1.3
Total proved	83.1	69.6	60.0	53.0	47.7	69.4	58.1	50.3	44.5	40.1
Probable	33.1	23.7	18.1	14.5	12.0	22.6	16.0	12.1	9.7	8.0
Total proved plus probable	116.2	93.3	78.2	67.6	59.7	92.0	74.1	62.4	54.2	48.1

Total future net revenue (undiscounted)
As of December 31, 2005
Constant prices and costs

Reserves category ($ thousands)	Revenue	Royalties, ARTC	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
Proved reserves	142,471	19,558	34,542	2,272	3,025	83,074	13,679	69,395
Proved plus probable reserves	195,305	27,763	45,701	2,635	3,025	116,181	24,208	91,973

Future net revenue by production group
As of December 31, 2005
Constant prices and costs

Reserves category ($ thousands)	Production group	Future net revenue before income taxes (discounted at 10 percent per year)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	32,504
	Natural gas (including by-products but excluding solution gas from oil wells)	25,352
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	38,574
	Natural gas (including by-products but excluding solution gas from oil wells)	36,908

RESERVES DATA - FORECAST PRICES AND COSTS

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2005
Forecast prices and costs

Reserves category	Reserves: Light and medium oil Gross (mbbls)	Net (mbbls)	Natural gas liquids Gross (mbbls)	Net (mbbls)	Natural gas Gross (mmcf)	Net (mmcf)	Total Gross (mboe)	Net (mboe)
Proved								
Developed producing	1,749	1,625	11	7	4,063	3,154	2,437	2,159
Developed non-producing	51	45	11	7	2,329	1,728	451	340
Undeveloped	36	89	-	-	54	77	45	102
Total proved	1,837	1,760	22	15	6,446	4,959	2,933	2,601
Probable	526	493	9	6	3,109	2,386	1,053	897
Total proved plus probable	2,362	2,253	31	21	9,556	7,345	3,986	3,498

Reserves category ($ millions)	Net present values of future net revenue: Before income taxes discounted at (percent per year) 0	5	10	15	20	After income taxes discounted at (percent per year) 0	5	10	15	20
Proved										
Developed producing	63.9	54.8	48.3	43.4	39.6	56.4	48.4	42.6	38.3	35.0
Developed non-producing	12.2	9.9	8.4	7.3	6.5	8.1	6.5	5.4	4.7	4.1
Undeveloped	3.9	3.2	2.7	2.3	2.0	2.6	2.1	1.7	1.5	1.3
Total proved	80.0	67.9	59.3	52.9	48.0	67.1	57.0	49.7	44.4	40.3
Probable	29.3	20.5	15.5	12.3	10.2	20.0	13.8	10.3	8.2	6.8
Total proved plus probable	109.3	88.4	74.8	65.3	58.3	87.2	70.8	60.1	52.6	47.1

Total future net revenue (undiscounted)
As of December 31, 2005
Forecast prices and costs

Reserves category	Revenue	Royalties, ARTC	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
($ thousands)								
Proved reserves	147,027	19,025	41,469	2,357	4,201	79,977	12,830	67,147
Proved plus probable reserves	199,997	26,106	57,388	2,744	4,504	109,255	22,066	87,189

Future net revenue by production group
As of December 31, 2005
Forecast prices and costs

Reserves category	Production group	Future net revenue before income taxes (discounted at 10 percent per year)
($ thousands)		
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	35,869
	Natural gas (including by-products but excluding solution gas from oil wells)	21,482
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	42,440
	Natural gas (including by-products but excluding solution gas from oil wells)	29,859

Notes to reserves data tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserves estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is provided below.

Reserves categories
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- *analysis of drilling, geological, geophysical and engineering data;*
- *the use of established technology; and*
- *specified economic conditions.*

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of certainty for reported reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. FORECAST PRICES AND COSTS

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at January 1, 2006, inflation and exchange rates utilized by McDaniel in the McDaniel Report (which were McDaniel's then current forecast at the date of the McDaniel Report) were as follows.

Summary of pricing and inflation rate assumptions
As of December 31, 2005
Forecast prices and costs

	Oil [1]			*Natural gas*	*Natural gas liquids*		
Year	*WTI Cushing Oklahoma*	*Edmonton par price 40° API*	*Bow River medium 25° API*	*AECO gas price*	*Edmonton mix*	*Inflation rates* [1]	*Exchange rate* [2]
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/bbl)*	*($Cdn/GJ)*	*($Cdn/bbl)*	*(%/year)*	*($US/$Cdn)*
Forecast							
2006	57.50	66.60	45.70	10.05	51.40	2.5	0.85
2007	55.40	64.20	45.30	9.05	48.90	2.5	0.85
2008	52.50	60.70	44.00	8.05	45.80	2.5	0.85
2009	49.50	57.20	42.60	7.00	42.60	2.5	0.85
2010	46.90	54.10	40.30	6.55	40.20	2.5	0.85
Thereafter	+ 2.5%/yr	+ 2.5%/yr	+ 2.5%/yr	+ 2.5%/yr	+ 2.5%/yr	+ 2.5%/yr	0.85

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2005, were $8.87 per mcf for natural gas, $44.82 per bbl for crude oil and $55.19 per bbl for natural gas liquids.

4. CONSTANT PRICES AND COSTS

Constant prices and costs are:

(a) the Corporation's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Corporation's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the McDaniel Report were as follows.

Summary of pricing assumptions
As of December 31, 2005
Constant prices and costs

Year	Oil (1) WTI WTI NYMEX	Oil (1) Edmonton par price 40° API	Oil (1) Bow River medium 25° API	Natural gas Alberta average gas price	Natural gas liquids Edmonton mix	Exchange rate(2)
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/GJ)	($Cdn/bbl)	($US/$Cdn)
Historical (2)						
2005+	61.04	68.46	36.71	9.80	56.30	0.8577

Notes:
(1) The exchange rate as at December 30, 2005
(2) As at December 30

5. FUTURE DEVELOPMENT COSTS

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below.

	Forecast prices and costs				Constant prices and costs	
	Proved reserves		Proved plus probable reserves		Proved reserves	
	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities
($ thousands)						
2006	479	1,722	579	1,776	468	1,680
2007	-	-	-	-	-	-
2008	-	-	108	-	-	-
2009	-	-	41	-	-	-
2010	-	-	85	-	-	-
Thereafter	90	64	90	64	75	50
Total undiscounted	569	1,786	903	1,840	543	1,730
Total discounted at 10%	525	1,645	813	1,668	503	1,603

In all the years of the economic forecasts, the net revenues from the reserves are well in excess of the estimated future development costs. Therefore, the Corporation can meet the funding requirements for future development entirely out of its cash flow and no other source of funding is required to develop the proved or the proved plus probable reserves.

6. The Alberta Royalty Tax Credit is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995.

7. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.

8. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

9. The extent and character of all factual data supplied to McDaniel, were accepted by McDaniel, as represented. No field inspection was conducted.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reconciliation of company gross reserves by principal product type
Forecast prices and costs

	Light and medium oil			Natural gas liquids			Associated and non-associated gas		
	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mmcf)
December 31, 2004	1,383	342	1,725	24	8	32	4,892	1,571	6,463
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	202	51	253	2	1	3	(272)	(254)	(526)
Discoveries	494	132	626	-	-	-	1,239	652	1,891
Acquisitions	12	1	13	-	-	-	1,783	1,140	2,923
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(254)	-	(254)	(4)	-	(4)	(1,196)	-	(1,196)
December 31, 2005	1,837	526	2,363	22	9	31	6,446	3,109	9,555

Reconciliation of changes in net present values of future net revenue after tax
Discounted at 10 percent per year
Proved reserves
Constant prices and costs

Period and factor	*2005*
($millions)	
Estimated future net revenue at beginning of year	23.8
Sales and transfers of oil and gas produced, net of production costs and royalties	(7.0)
Net change in prices, production costs and royalties related to future production	16.6
Changes in previously estimated development costs incurred during the period	-
Changes in estimated future development costs	(1.3)
Extensions and improved recovery	3.5
Discoveries	8.9
Acquisitions of reserves	12.3
Dispositions of reserves	-
accretion of discount	0.7
Net change in income taxes	(7.2)
Estimated future net revenue at end of year	50.3

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped reserves

Proved undeveloped reserves

Proved undeveloped reserves are within the following categories:

- *Wells budgeted and scheduled to be drilled in 2006.*
- *Gas caps that will be blown down once the oil has been depleted.*
- *Secondary zones that will be brought on production once the primary zone has been depleted.*

The Corporation does not carry proved undeveloped reserves for long periods of times.

Probable undeveloped reserves

The Corporation's probable reserves are attributed to more optimistic recoveries from producing wells. The remaining probable reserves for the most part are attributed to step-out drilling locations, recompletions, and tie-ins that are anticipated to proceed in the near term but do not meet the required confidence factor to be booked as proved. The comments regarding the Corporation's efforts to put proved undeveloped reserves onstream also apply to probables.

Significant factors or uncertainties

Estimates of economically recoverable oil and natural gas reserves (including NGL) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from the actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

OTHER OIL AND GAS INFORMATION

Principal properties

Following is a description of Masters oil and natural gas properties as at December 31, 2005. Production stated is net to Masters. Reserves amounts are stated, before deduction of royalties, at December 31, 2005 based on forecast costs and prices as evaluated in the McDaniel Report (see "Reserves Data"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2005.

Little Bow, Alberta

Masters purchased the Little Bow property on December 22, 2003. Little Bow is located 50 miles north of Lethbridge, Alberta. Masters has an average working interest of 48 percent in 5,960 (2,856 net) acres of developed land and an average 61 percent working interest in 4,160 (2,534 net) acres of undeveloped lands. As at December 31, 2005, 29 wells were producing and Masters operated the majority of these wells.

During 2004, Masters conducted an independent reservoir simulation study on the Glauconite oil pool and concluded that further infill drilling and waterflood optimization would enhance the recovery of hydrocarbons. Masters successfully drilled 6 (6.0 net) infill wells in 2005 and enhanced the waterflood effectiveness by expanding the water handling facility and drilling a water injection well. Masters also shot a 3D seismic program on some of the exploration lands held in this area. The area offers multi-zone oil and natural gas potential at depths to approximately 1,400 meters.

In addition to the wells drilled in the Glauconite oil pool, four (2.6 net) exploration wells were drilled resulting in two (1.5 net) natural gas wells.

McDaniel estimated total proved reserves to be 1,578 mbbls of crude oil and NGL and 1,136 mmcf of natural gas as at December 31, 2005. Production averaged 594 bbls/d (2004 - 467 bbls/d) of crude oil and NGL and 208 mcf/d (2004 - 201 mcf/d) of natural gas for the year ended December 31, 2005.

Badger, Alberta

The Badger area is located 60 miles north of Lethbridge, Alberta. Masters has an average working interest of 24 percent in 2,460 (601 net) acres of developed land and an average 53 percent working interest in 2,400 (1,280 net) acres of undeveloped land. As at December 31, 2005, three (0.6 net) producing wells were in the area.

A Glauconite natural gas well (0.3 net) drilled in 2003 commenced production in April 2004.

McDaniel estimated total proved reserves to be 3.8 mbbls of NGL and 633 mmcf of natural gas as at December 31, 2005. Production averaged 3 bbls/d (2004 - 2 bbls/d) of NGL and 412 mcf/d (2004 - 359 mcf/d) of natural gas for the year ended December 31, 2005.

Roche, Alberta

Masters holds working interests of 33 to 50 percent in 59 sections of undeveloped land and 1,905 (315 net) acres of developed land in the Roche area, 30 miles northeast of Swan Hills.

Masters has identified a number of drilling locations for Lower Mannville or Belly River potential reservoirs. In 2004 three wells were drilled resulting in one natural gas well. In 2005, one natural gas well was drilled and commenced production in the second quarter. Masters has scheduled five wells for drilling during the 2006 winter season.

McDaniel estimated total proved reserves to be 37 mmcf of natural gas as at December 31, 2005. Production averaged 77 mcf/d (2004 - 55 mcf/d) of natural gas for the year ended December 31, 2005.

Eyremore, Alberta

The Eyremore area is located approximately 30 miles east of the town of Vulcan. Masters has a 100 percent working interest in 4,800 acres of undeveloped land in this area.

The primary exploration target in this area is the Ostracod zone, at depths of 1,200 metres, with secondary targets in the Upper and Lower Mannville zones. During 2004, one natural gas well was drilled and brought on stream in November 2004 at 1.2 mmcf/d. In 2005 three natural gas wells were drilled and brought on stream in November 2005.

McDaniel estimated total proved reserves in this area to be 536 mmcf of natural gas and 1,970 bbls of NGL at December 31, 2005.

Production from the Eyremore area averaged 958 mcf/d (2004 - 279 mcf/d) of natural gas and 4 bbls/d (2004 - 2 bbls/d) of crude oil and NGL for the year ended December 31, 2005.

Iron Springs, Alberta

The Iron Springs area is located approximately 10 miles north of the city of Lethbridge. Masters has an average working interest of 92 percent in 12,440 (11,420 net) acres of land and six (6.0 net) producing natural gas wells and one (1.0 net) cased natural gas well in this area.

McDaniel estimated total proved natural gas reserves in this area to be 394 mmcf at December 31, 2005.

Production from the Iron Springs area averaged 346 mcf/d (2004 - 412 mcf/d) of natural gas for the year ended December 31, 2005.

Long Coulee, Alberta

The Long Coulee area is located approximately 30 miles north of the city of Lethbridge. Masters has an average 23 percent working interest in 1,598 (3633 net) acres of undeveloped land and nine (4.5 net) producing oil wells in this area.

McDaniel estimated total proved reserves in this area to be 113 mbbls of crude oil and 43 mmcf of natural gas at December 31, 2005.

Production from the Long Coulee area averaged 39 bbls/d (2004 - 33 bbls/d) of crude oil and 14 mcf/d (2004 - 15 mcf/d) of natural gas for the year ended December 31, 2005.

McLeans Creek, Alberta

The McLeans Creek area is located approximately 35 miles west of the town of High Prairie. Masters has an average working interest of 47 percent in 39,680 (18,452 net) acres of undeveloped land and three (1.3 net) producing oil wells in this area. The primary crude oil exploration target is the Granite Wash zone, with secondary natural gas targets in the Bluesky and Paddy zones. During 2004, Masters drilled and abandoned one well. In 2006 Masters plans to re-enter one well and drill another well on a Mississippian natural gas prospect. If successful, several follow up drilling locations have been identified.

McDaniel estimated total proved crude oil reserves in this area to be 39 mbbls at December 31, 2005.

Production from the McLeans Creek area averaged 30 bbls/d (2004 - 28 bbls/d) of crude oil for the year ended December 31, 2005.

Robin, Alberta

The Robin area is located approximately 20 miles northeast of the city of Lethbridge. Masters has an average working interest of 70 percent in 2,530 (1,644 net) acres of land and six (4.0 net) producing natural gas wells.

During 2004, two (1.4 net) wells were drilled resulting in one (0.6 net) natural gas well and one (0.8 net) well suspended.

McDaniel estimated total proved reserves in this area to be 487 mmcf of natural gas and 2 mbbls of NGL at December 31, 2005.

Annualized production from the Robin area averaged 1 bbl/d (2004 - 1 bbl/d) of NGL and 407 mcf/d (2004 - 331 mcf/d) of natural gas for the year ended December 31, 2005.

North Peace River Arch area, Alberta

The North Peace River Arch area is located west of the town of Peace River. Early in 2005 Masters successfully drilled two (1.0 net) gas wells in this area. Commencing June 2005 Masters made several acquisitions for a total of $7.2 million and created a second core producing area for Masters. The acquisitions provided 160 boe/d of production (approximately 95 percent natural gas), 10,600 net undeveloped acres, ownership in several strategic field facilities and a large seismic data base associated with the properties.

In addition to the acquisitions the Company drilled a total of six wells, four of which were natural gas wells, recompleted another six wells, acquired 10,528 net undeveloped acres, expanded existing production facilities and shot several large 3D seismic programs. Also, the Company entered into several farm-in agreements and has option acreage of 19,200 acres under its control. On a section equivalent basis, this option land position translates to 30 sections. At the end of 2005 and into the early part of 2006 Masters shot approximately 94 square miles of 3D seismic. For 2006 the Company plans to drill approximately 20 to 25 (6 to 12 net) oil and gas wells at depths ranging from 400 to 1,900 meters. Generally the drilling prospects are multi-zone type wells targeting the Montney,

Masters has an average working interest of 24 percent in 27,264 (6,632 net) acres of developed land and an average 29 percent working interest in 90,809 (26,133 net) acres of undeveloped lands. As at December 31, 2005, 33 (7.2 net) wells were producing.

McDaniel estimated total proved reserves to be 66 mbbls of crude oil 2,265 mmcf of natural gas as at December 31, 2005. Production averaged 3 bbls/d (2004 - nil bbls/d) of crude oil and 809 mcf/d (2004 - nil) of natural gas for the year ended December 31, 2005.

Other properties and projects

Firebird, Alberta

The Firebird area is located approximately 150 miles north of the town of Slave Lake. Masters has a 100 percent working interest in 160 acres of developed land and one (1.0 net) shut-in natural gas well in this area.

McDaniel estimated total proved reserves in this area to be 652 mmcf of natural gas and 28 mbbls of crude oil and NGL at December 31, 2005.

The Firebird area did not have any production for the year ended December 31, 2005. The well produced from May through November of 2003, when it was shut-in awaiting throughput capacity at a third party processing facility. Production is expected to recommence in mid-2006.

Minor properties

Masters has additional minor producing properties in the Brazeau, Edson, Grand Forks and Queenstown areas of southern Alberta.

Oil and gas wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2005.

	Oil				Natural gas			
	Producing		Non-producing		Producing		Non-producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
(wells)								
Alberta	63	41.6	50	31.9	49	18.5	67	27.6
Total	63	41.6	50	31.9	49	18.5	67	27.6

Properties with no attributable reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2005.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
(acres)						
Alberta - Northern	34,104	9,463	190,411	75,468	224,515	84,931
Alberta - Southern	23,319	15,495	32,367	24,298	55,686	39,793
Total	57,423	24,958	222,778	99,766	280,201	124,724

The Corporation expects that rights to explore, develop and exploit 20,387 net acres of its undeveloped land holdings will expire by December 31, 2006.

Forward contracts

Masters sells crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters' natural gas production is sold to natural gas aggregators at spot market prices. Masters does not have any hedge commitments in place at December 31, 2005.

Additional information concerning abandonment and reclamation costs

The Corporation estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities through its previous experience, where available, or by estimating such costs. The Corporation expects to incur abandonment and reclamation costs on 240 gross wells (130.2 net wells) including currently producing, non-producing wells and service wells as indicated above.

	Constant pricing		Forecast pricing		Forecast pricing	
($ thousands)	Proved NPV0%	Proved NPV10%	Proved NPV0%	Proved NPV10%	Proved plus probable NPV0%	Proved plus probable NPV10%
Associated with producing wells	2,170	875	3,205	1,147	3,205	977
Associated with non-producing, shut-in or no assigned reserves to wells	855	345	996	357	1,300	396
Total	3,025	1,220	4,201	1,504	4,505	1,373
Portion forecasted to be paid in next 3 years	458	369	490	395	490	395

Tax horizon

The income taxes deducted in the calculation of future net revenue above assumes a blow down scenario whereby the Corporation produces out its existing reserves. Under this scenario the Corporation is taxable in 2006. The Corporation forecasts its tax horizon assuming a continuing business model whereby it reinvests cash flow at historic capital efficiencies in order to achieve minimum production and reserves growth. Under this scenario the Corporation does not forecast being in a taxable position in 2006. The results are dependent upon commodity prices and capital spending levels.

Capital expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2005.

($ thousands)	
Property acquisition costs - unproved properties	2,401
Property acquisition costs - proved properties	7,244
Exploration costs	9,649
Development costs	8,239
Total	27,533

Exploration and development activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2005.

(wells)	Gross	Net
Light and medium oil	6	6.0
Natural gas	10	7.2
Dry	6	4.4
Total	22	17.6

For details on the most important current and likely exploration and development activities during 2005, see "Principal Properties".

Production estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2006 which is reflected in the estimate of proved reserves future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Light and medium oil	Natural gas	Natural gas liquids	Total production
	(bbls/d)	(mcf/d)	(bbls/d)	(boe/d)
2006	866	4,793	12	1,677

Production history

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and the resulting netback for the periods indicated below.

	Quarter ended 2005			
	Dec 31	Sep 30	Jun 30	Mar 31
Average daily production [1]				
Light and medium crude oil *(bbls/d)*	707	688	715	678
Natural gas *(mcf/d)*	3,619	3,872	3,055	2,538
NGL *(bbls/d)*	10	15	11	6
Total *(boe/d)*	1,320	1,349	1,236	1,107
Average price received				
Light and medium crude oil *($/bbl)*	42.50	56.92	41.64	38.14
Natural gas *($/mcf)*	11.29	9.09	7.34	6.83
NGL *($/bbl)*	60.85	59.56	49.56	46.12
Combined *($/boe)*	54.18	55.84	42.71	39.28
Royalties paid				
Light and medium crude oil *($/bbl)*	7.75	7.93	6.70	6.22
Natural gas *($/mcf)*	4.19	1.64	1.49	1.39
NGL *($/bbl)*	21.97	11.86	14.67	17.58
Combined *($/boe)*	14.95	8.26	7.70	6.13
Operating expenses [2]				
Light and medium crude oil *($/bbl)*	11.69	9.93	7.43	9.57
Natural gas *($/mcf)*	2.13	1.04	1.48	0.96
NGL *($/bbl)*	-	-	-	-
Combined *($/boe)*	12.11	8.06	7.96	8.05
Netback received [2]				
Light and medium crude oil *($/bbl)*	23.06	39.06	27.51	22.35
Natural gas *($/mcf)*	4.97	6.67	4.37	4.48
NGL *($/bbl)*	38.88	43.98	34.89	28.54
Total *($/boe)*	27.12	39.52	27.05	25.10

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues. Operating costs have not been allocated to the natural gas liquids netback presented but are borne by the primary product, natural gas.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2005.

	Light and medium crude oil (bbls/d)	Natural gas (mcf/d)	NGL (bbls/d)	Total (boe/d)
Little Bow	594	208	-	629
Badger	-	412	3	71
Eyremore	-	958	4	164
Iron Springs	-	346	-	57
North Peace River Arch	3	809	-	138
Robin	-	407	1	70
Other	100	136	3	125
Total Alberta	697	3,276	11	1,254

For the year ended December 31, 2005, approximately 56 percent of Masters gross revenue was derived from crude oil production and 44 percent was derived from natural gas production.

Marketing

Masters sells crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters' natural gas production is sold to natural gas aggregators at spot market prices.

MANAGEMENT'S REPORT

All of the information in Masters Energy Inc.'s annual report is the responsibility of management and has been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect management's best judgments. Management has determined such amounts on a reasonable basis to ensure that the financial statements are presented fairly, in all material respects. The financial information throughout the annual report has been reviewed to ensure consistency in all material respects with that in the financial statements.

The Company maintains appropriate systems of internal control to provide reasonable assurance that, transactions are authorized, to safeguard assets from loss or unauthorized use and to produce reliable and accurate financial records for the preparation of financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board exercises this responsibility through the Audit Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation.

The Audit Committee, composed entirely of independent Directors, meets at least on a quarterly basis with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the financial statements and Management's Discussion and Analysis before they are presented to the Board of Directors for approval. On the recommendation of the Audit Committee, the financial statements and Management's Discussion and Analysis have been approved by the Board of Directors. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of external auditors.

KPMG LLP, an independent firm of chartered accountants, has been appointed by a vote of shareholders at the Company's last annual meeting to audit the financial statements in accordance with Canadian generally accepted auditing standards and to provide their auditors' report. Their report is presented with the financial statements. KPMG LLP has full and free access to the Audit Committee.

Geoff C. Merritt
President and Chief Executive Officer
March 20, 2006

Randall P. Boyd
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Masters Energy Inc.

We have audited the balance sheets of Masters Energy Inc. as at December 31, 2005 and 2004 and the statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on those financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 15, 2006

MASTERS ENERGY INC.

BALANCE SHEETS

As at December 31,		2005		2004
($ thousands)				
Assets				
Current assets				
Accounts receivable	$	3,608	$	2,116
Prepaid expenses and deposits		190		415
		3,798		2,531
Property and equipment *(note 3)*		56,218		34,760
	$	60,016	$	37,291
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	$	8,811	$	3,223
Bank debt *(note 4)*		-		3,424
		8,811		6,647
Long-term bank debt *(note 4)*		14,093		-
Asset retirement obligations *(note 5)*		3,316		3,044
Future income taxes *(note 9)*		2,005		30
		28,225		9,721
Shareholders' equity				
Share capital *(note 6)*		27,469		27,042
Contributed surplus *(note 7)*		393		210
Retained earnings		3,929		318
		31,791		27,570
	$	60,016	$	37,291

See accompanying notes to the financial statements.

Approved on behalf of the Board,

William R. Stedman, *Director*

Douglas H. Mitchell, *Director*

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

For the years ended December 31,		*2005*		*2004*
($ thousands, except share and per share amounts)				
Revenue				
Petroleum and natural gas revenue	$	**22,216**	$	11,680
Royalty and other revenue		**713**		298
		22,929		11,978
Royalties, net of Alberta Royalty Tax Credit		**(4,695)**		(2,379)
		18,234		9,599
Expenses				
Operating		**4,168**		2,853
General and administrative		**1,436**		1,077
Interest - long-term debt		**322**		-
- short-term debt		**92**		112
Depletion, depreciation and accretion		**6,627**		4,467
		12,645		8,509
Earnings before taxes		**5,589**		1,090
Taxes *(note 9)*				
Capital		**3**		-
Future		**1,975**		662
		1,978		662
Net earnings		**3,611**		428
Retained earnings (deficit), beginning of year		**318**		(110)
Retained earnings, end of year	$	**3,929**	$	318
Earnings per share *(note 8)*				
Basic	$	**0.25**	$	0.03
Diluted	$	**0.24**	$	0.03
Weighted average number of shares outstanding *(note 8)*				
Basic		**14,420,197**		13,521,707
Diluted		**15,090,130**		13,716,226

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the years ended December 31,		2005		2004
($ thousands)				
Cash provided by (used for):				
Operating activities				
Net earnings	$	**3,611**	$	428
Add (deduct) non-cash items				
Depletion, depreciation and accretion		**6,627**		4,467
Future income tax expense		**1,975**		662
Stock-based compensation expense		**227**		172
Settlement of asset retirement costs *(note 5)*		**(281)**		(95)
Funds generated by operations		**12,159**		5,634
Changes in non-cash working capital		**3,087**		731
		15,246		6,365
Financing activities				
Increase (decrease) in bank debt *(notes 2 and 4)*		**10,669**		(7,032)
Proceeds on share issuance		**383**		-
		11,052		(7,032)
Changes in non-cash working capital		**-**		3,424
		11,052		(3,608)
Investing activities				
Petroleum and natural gas properties				
Exploration and development		**(20,289)**		(10,920)
Producing property acquisitions		**(7,244)**		-
Costs related to the acquisition of Terraquest *(note 2)*		**-**		(295)
		(27,533)		(11,215)
Changes in non-cash working capital		**1,235**		(1,057)
		(26,298)		(12,272)
Decrease in cash and cash equivalents		**-**		(9,515)
Cash and cash equivalents, beginning of year		**-**		9,515
Cash and cash equivalents, end of year	$	**-**	$	-
Supplemental cash flow information				
Interest income received	$	**6**	$	28
Interest paid	$	**470**	$	56
Capital taxes paid	$	**-**	$	34

See accompanying notes to the financial statements.

For the years ended December 31, 2005 and 2004
(tabular amounts in $ thousands, except share and per share amounts)

Description of business
Masters Energy Inc. is engaged in the exploration, development and production of petroleum and natural gas in western Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation
The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(b) Cash and cash equivalents
Cash and cash equivalents consisted of amounts on deposit with banks and term deposits with original maturities of less than 90 days.

(c) Property and equipment
The Company follows the full cost method for accounting for petroleum and natural gas operations whereby all costs related to the exploration for and the development of petroleum and natural gas reserves are capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and production and well equipment.

Costs capitalized together with future capital costs are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified reserves evaluators at future prices and costs. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The cost of significant unproved properties is excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

The Company performs a ceiling test for impairment for each cost centre in a two-stage test undertaken at least annually.

(i) Impairment is recognized if the carrying value of the petroleum and natural gas properties, less accumulated depletion and depreciation, exceeds the estimated future cash flows from proved oil and natural gas reserves, on an undiscounted basis, using forecast prices and costs and the lower of cost and fair value of unproven properties. Future cash flows are calculated before interest, general and administrative expenses and income taxes.

(ii) If impairment is indicated by applying the calculations described in (i) above, the Company will measure the amount of the impairment by comparing the carrying value of the petroleum and natural gas properties less accumulated depletion and depreciation to the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at a risk-free rate of interest, using forecast prices and costs and the lower of cost and fair value of unproven properties. Any impairment recognized is recorded as additional depletion and depreciation expense.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion and depreciation by 20 percent or more.

The costs of corporate and other office equipment are amortized at rates approximating their useful life on a declining balance basis of 30 percent per year.

(d) Joint ventures

Substantially all of the Company's exploration and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(e) Asset retirement obligations

The Company recognizes the liability for retirement obligations associated with the abandonment of petroleum and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by Company management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related oil and natural gas properties, and a corresponding liability is recognized. This component of the increase in petroleum and natural gas properties is depleted and depreciated on the same basis as the remainder of the petroleum and natural gas properties. The liability is adjusted for accretion charged to income until the obligation is settled or sold and for revisions to the estimated cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

(f) Flow-through shares

From time to time, the Company issues flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital is reduced and a future tax liability is recorded equal to the estimated amount of future income taxes payable by the Company as a result of the renunciations, when the expenditures are renounced.

(g) Stock-based compensation

The Company issues stock options and performance warrants to directors, officers, employees and other service providers as described in note 7. Compensation cost, attributable to stock options and performance warrants granted, is measured by the fair value method of accounting at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. When stock options or performance warrants are exercised, the cash proceeds together with the amount previously recorded as contributed surplus are recorded as share capital. The Company does not incorporate an estimated forfeiture rate for stock options and performance warrants that will not vest, but accounts for forfeitures as they occur.

(h) Revenue recognition and operating expenses

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(i) Income taxes

Future income taxes are accounted for using the liability method of income tax allocation. Under the liability method, income tax assets and liabilities are recorded to recognize future tax income inflows and outflows arising from the settlement or recovery of assets and liabilities at the carrying values. Income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those liabilities are more likely than not to be realized. Future income tax assets and liabilities are determined based on the income tax laws and rates that are anticipated to apply in the period of reversal.

(j) Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. The Company utilizes the treasury stock method for the calculation of diluted per share amounts. This method assumes that the proceeds from the exercise of in-the-money stock options and warrants plus the unamortized stock-based compensation are used to repurchase Company shares at the weighted average market price during the period.

(k) Measurement uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties, the asset retirement obligation and the ceiling test are based on estimates. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income effect are based on estimates of the future volatility of the Company's share price, expected lives of the options, expected dividends and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

(l) Financial instruments

The Company has a price risk management program whereby the commodity price associated with a portion of its future production can be fixed. The Company is able to sell forward a portion of its future production through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward and future contracts are subject to market risk from fluctuating commodity prices and exchange rates; however, gains or losses on the contracts are offset by changes in the value of the Company's production and recognized in income in the same period and category as the hedged item.

(m) Reclassification

Certain information provided for the prior year has been reclassified to conform to the presentation adopted in 2005.

2. BUSINESS COMBINATION

On February 26, 2004, Masters Energy Inc. (the "Company"), a private company incorporated under the Alberta Business Corporations Act on August 28, 2003 and Terraquest Energy Corporation, a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. After giving effect to the transaction, Amalco had approximately 14.4 million Common Shares outstanding, of which former Masters' securityholders owned approximately 62 percent and former Terraquest shareholders owned approximately 38 percent.

The business combination has been accounted for using the purchase method as a reverse takeover of Terraquest by the Company and earnings of Terraquest are recognized from the acquisition closing date of February 26, 2004.

The Terraquest purchase was valued based on the discounted proved plus probable reserves acquired as determined by an independent reserves evaluation. Land cost values were estimated by Masters staff. The share consideration value of acquiring Terraquest was based on Masters common share fair value at the date of amalgamation. The purchase price was allocated as follows:

Property and equipment	$	19,584
Future income tax recoverable		903
Working capital deficiency		(694)
Fair value of hedging commitment		(199)
Bank debt		(7,032)
Asset retirement obligations		(1,770)
	$	10,792
Purchase price		
Share consideration	$	10,497
Acquisition costs		295
	$	10,792

3. PROPERTY AND EQUIPMENT

As at December 31, 2005		*Cost*		*Accumulated depletion and depreciation*		*Net book value*
Petroleum and natural gas properties and well equipment	**$**	**66,992**	**$**	**10,820**	**$**	**56,172**
Office equipment		**73**		**27**		**46**
	$	**67,065**	**$**	**10,847**	**$**	**56,218**
As at December 31, 2004						
Petroleum and natural gas properties and well equipment	$	39,052	$	4,317	$	34,735
Office equipment		42		17		25
	$	39,094	$	4,334	$	34,760

The value of undeveloped lands excluded from costs subject to depletion was $8.7 million at December 31, 2005 ($5.5 million - December 31, 2004).

As at December 31, 2005, $0.6 million ($0.5 million - December 31, 2004) of general and administrative costs were capitalized.

The benchmark and Company prices on which the December 31, 2005 ceiling test for impairment is based, are as follows:

	Oil		Natural gas		Natural gas liquids	
	Bow River medium benchmark	Company	AECO Spot benchmark	Company	Edmonton benchmark	Company
	($/bbl)	($/bbl)	($/GJ)	($/mcf)	($/bbl)	($/bbl)
2006	45.70	46.73	10.05	10.52	51.40	60.05
2007	45.30	46.46	9.05	9.47	48.90	57.71
2008	44.00	44.50	8.05	8.39	45.80	53.55
2009	42.60	42.51	7.00	7.48	42.60	54.89
2010	40.30	39.89	6.55	6.92	40.20	51.87

Prices increase at a rate of approximately 2.5 percent per year for oil, natural gas and natural gas liquids after 2010. Adjustments were made to the benchmark prices, for purposes of the ceiling test, to reflect varied delivery points and quality differentials in the products delivered.

4. BANK DEBT

The Company has access to a revolving term credit facility with a Canadian chartered bank to a maximum of $18.0 million. The credit facility may be drawn with advances or bankers' acceptances or repaid. Direct advances bear interest at the bank's prime lending rate and the bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a stamping fee.

The Company has available a $2.5(USD) million demand swap facility, to assist in financing the contingent exposure of settlement for financial commodity swaps. The facility bears interest at a US base rate per annum on amounts drawn.

The revolving term credit facility is available for a period of 364 days until April 30, 2006. Up to 60 days prior to April 30, 2006 the Company may request an extension of the revolving facility for a period of another 364 days, subject to the bank's approval. If the Company does not request the extension or the bank does not agree to the extension, the credit facility principal borrowed will be repaid in full with a single payment 366 days subsequent to April 30, 2006. The nature of the lending facility is such that it is recognized as a long-term liability. The credit facility will revolve until April 30, 2006, at which time a review of the facility will occur.

As of December 31, 2005, $14.1 million ($3.4 million - December 31, 2004) has been drawn against the revolving term credit facility.

As at December 31, 2004 the Company had access to a demand revolving credit facility of $8.5 million of which $3.4 million had been drawn against the facility.

Security pledged for the facilities consists of a general assignment of book debts, a $40.0 million demand debenture, secured by a first floating charge over all the assets of the Company. The Company is not in breach of any covenants under its credit facility.

5. ASSET RETIREMENT OBLIGATIONS

The following table summarizes changes in the asset retirement obligation for the years ended December 31, as indicated:

		2005		2004
Asset retirement obligations, beginning of year	$	**3,044**	$	1,198
Adjustments		**(256)**		(119)
Liabilities acquired		**305**		1,770
Liabilities incurred		**390**		119
Settlement of asset retirement costs		**(281)**		(95)
Accretion expense		**114**		171
Asset retirement obligations, end of year	$	**3,316**	$	3,044

The total estimated, undiscounted cash flows required to settle the obligations as at December 31, 2005, before considering salvage, is $4.6 million ($4.4 million - 2004) which has been discounted using a weighted average credit-adjusted risk-free interest rate of 5.9 percent. The Company expects these obligations to be settled in approximately 1 to 14 years.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of voting common shares, without nominal or par value

Unlimited number of preferred shares, issuable in series, with rights and privileges to be determined at the time of issuance by the Board of Directors

(b) Issued	*Number*		*Amount*
Warrants and common shares balance, December 31, 2003	17,752,001	$	16,545
Warrants and shares exchanged per plan of arrangement	(17,752,001)		-
Issued to Masters Energy Inc. shareholders on reverse takeover of Terraquest *(note 2)*	8,876,000		-
Issued to Terraquest shareholders at date of acquisition *(note 2)*	5,487,647		10,497
Common shares, December 31, 2004	14,363,647		27,042
Exercise of stock and performance warrants	159,666		383
Transfer from contributed surplus for exercise of options and warrants	-		44
Common shares, December 31, 2005	**14,523,313**	**$**	**27,469**

On October 28 and November 25, 2003, the Company closed private placements of 16,002,000 common special warrants and 1,750,000 flow-through special warrants for gross proceeds of $17.8 million. Both the common special warrants and flow-through special warrants were issued at $1.00 per special warrant, were convertible to common shares at a rate of one warrant to one common share at no additional cost upon either demand, or the Company obtaining a public listing. Effective February 26, 2004, all special warrants were converted into common shares.

7. STOCK-BASED COMPENSATION PLANS

On February 26, 2004, the Company's stock-based compensation plans were revised to conform with the one for two share consolidation related to the acquisition of Terraquest Energy Corporation. This had the effect of halving the number of options that had been issued and doubling their exercise price. The plans are described below:

(a) Stock options

The Company's stock option plan allows for options to be granted to employees, officers, directors and other service providers. The number of shares which may be issued, and that have been reserved, under the plan is 1,435,042 common shares. The maximum number of shares that may be reserved for issuance to any one person under the plan is limited to five percent per year of the issued and outstanding Common Shares and Special Warrants for employees, officers and directors and two percent for other service providers. The plan also provides that the price at which options may be granted cannot be less than the market price of the common shares at the date of grant. Options granted under the plan have a maximum life of five years and vest at an equal amount over three years on the anniversary date of the grant or as determined by the Board of Directors.

The following tables summarizes information about the Company's stock options outstanding at December 31, 2005:

	Number of options	Weighted average exercise price
		($)
Balance, December 31, 2003	575,000	2.00
Granted, April 26, 2004	655,000	2.35
Granted, December 23, 2004	25,000	2.60
Balance, December 31, 2004	1,255,000	2.19
Granted, July 26, 2005	50,000	3.80
Cancelled	(83,334)	2.14
Exercised	(94,666)	2.09
Balance, December 31, 2005	**1,127,000**	**2.28**

As of December 31, 2005, 490,320 stock options (2004 - 191,667) have vested at an average exercise price of $2.11 per option (2004 - $2.00).

Exercise price per share($)	Options outstanding	Weighted average years to expiry
2.00	455,000	3.0
2.35	597,000	3.3
2.60	25,000	4.0
3.80	50,000	4.5
2.00 - 3.80	1,127,000	3.2

The Company has recorded compensation expense of $0.2 million as at December 31, 2005, (2004 - $0.2 million) for options and warrants vested during the period. Using the Black-Scholes model, assuming the expected life of the options and warrants are five years and no expected future dividends, the following table summarizes the total fair value of options and warrants granted.

Grant date	Options and warrants granted	Expected volatility	Risk-free interest rate	Total fair value
		(%)	(%)	($ thousands)
July 26, 2005	50,000	46	3.8	78
December 23, 2004	25,000	33	3.40	21
April 26, 2004	655,000	26	3.40	455
December 22, 2003	1,575,000	nil	3.95	207

(b) Performance warrants

The Company's Performance Warrants Plan allows for Performance Warrants to be granted to employees, officers and directors. The maximum number of shares which may be issued, and that have been reserved, under the plan is 1,000,000 common shares. Performance Warrants granted under the plan have a five year life, vest immediately and have no performance criteria other than the escalating exercise price. As at December 31, 2005, 870,000 Performance Warrants have been granted, expiring December 22, 2008, with the following exercise prices:

	Performance warrants outstanding and exercisable	Average exercise price per warrant ($)
	100,000	2.00
	100,000	2.50
	150,000	3.00
	150,000	3.50
	250,000	4.00
	250,000	4.50
Balance, December 31, 2004	1,000,000	3.55
Exercised	(65,000)	2.85
Unallocated	(65,000)	-
Balance, December 31, 2005	**870,000**	**3.55**

(c) Contributed surplus

The following table reconciles the Company's contributed surplus for the years ended December 31, as indicated.

	2005	2004
Balance, beginning of year	$ **210**	$ 38
Stock-based compensation expense	**227**	172
Exercise of options and performance warrants	**(44)**	-
Balance, end of year	$ **393**	$ 210

8. PER SHARE AMOUNTS

Earnings per share has been calculated using the basic weighted average number of common shares outstanding of 14,420,197 (13,521,707 - 2004) during the year ended December 31, 2005. As at December 31, 2005, a total of 669,933 (194,519 - 2004) were added to the total to take into account the dilutive effect of the options for the year.

9. INCOME TAXES

(a) The provision for income tax expense differs from that which would be expected from applying the combined effective Canadian federal and provincial income tax rate of 37.62 percent (38.62 percent - 2004) to income before income taxes. The difference results from the following:

	2005	*2004*
Expected income tax expense	**$ 2,103**	$ 423
Increase (decrease) resulting from:		
Non-deductible crown payments	**928**	565
Resource allowance	**(907)**	(480)
Change in effective income tax rate applied	**-**	(111)
Stock-based compensation expense	**85**	67
Other	**(234)**	198
Capital tax	**3**	-
Tax expense	**$ 1,978**	$ 662

(b) The components of the future income tax liability at December 31 are as follows:

	2005	*2004*
Carrying value of property and equipment in excess of available tax deductions	**$ 3,582**	$ 2,141
Asset retirement obligation	**(1,076)**	(987)
Non-capital loss carry forwards	**-**	(640)
Share issuance costs	**(286)**	(484)
Attributed Canadian Royalty Income	**(215)**	-
	$ 2,005	$ 30

As at December 31, 2005, the Company has tax pools of approximately $46.6 million ($31.9 million - 2004) available for deduction against future taxable income.

10. COMMITMENTS

As at December 31, 2005, the Company is committed under a lease on its office premises expiring August 2010. Future annual minimum rental payments excluding estimated operating costs for the remaining term of the lease are: 2006 - $87,000; 2007 - $87,000; 2008 - $89,000; 2009 - $93,000; 2010 - $62,000.

11. FINANCIAL INSTRUMENTS

(a) Fair values
The fair values of the Company's accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short-term maturity.

(b) Credit risk
The Company's credit risk is limited to the carrying amount of its accounts receivable, which are due primarily from other entities involved in the oil and gas industry. These amounts are subject to the same risks as the industry as a whole.

(c) Interest rate risk
The Company is exposed to interest rate risk to the extent the changes in market interest rates will impact the Company's debts that have a floating interest rate.

CORPORATE INFORMATION

DIRECTORS

Fred Coles[(1)(3)]
Calgary, Alberta
President, Menehune Resources Ltd.

Kerry Lyons[(3)]
DeWinton, Alberta
President and CEO, Greenfield Resources Ltd.

Geoffrey C. Merritt[(2)]
Calgary, Alberta
President and CEO, Masters Energy Inc.

Douglas H. Mitchell[(2)]
Calgary, Alberta
Co-Chairman and Managing Partner, Borden Ladner Gervais LLP

John W. (Jack) Peltier[(1)(2)]
Calgary, Alberta
President, Ipperwash Resources Ltd.

William R. Stedman[(1)(3)]
Calgary, Alberta
Chairman and CEO, ENTx Capital Corporation

(1) *Audit Committee*
(2) *Compensation Committee*
(3) *Reserves Committee*

OFFICERS

Geoffrey C. Merritt
President and CEO

Randall P. Boyd
Chief Financial Officer

Peter W. Goodman
Controller

INDEPENDENT QUALIFIED RESERVES EVALUATORS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Borden Ladner Gervais LLP
Calgary, Alberta

STOCK EXCHANGE AND LISTING

Toronto Stock Exchange "TSX"
Trading Symbol "MSY"

TRANSFER AGENT AND REGISTRAR

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AUDITOR

KPMG LLP
Calgary, Alberta

BANK

Canadian Imperial Bank of Commerce
Calgary, Alberta

CORPORATE AND REGISTERED OFFICE

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ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

The Calgary Telus Convention Centre
Room 206, 120 - 9 Avenue SE
Calgary, Alberta
Wednesday, May 3, 2006 at 2:00 pm (Calgary time)

Designed by Sandy Seifert Printed by Unicom Graphics

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